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Institute of Gas Technology, Chicago, Ill

Prepared for

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ALTERNATIVE FUELS FOR AUTOMOTIVE TRANSPORTATION - A FEASIBILITY STUDY

VOLUME II - TECHNICAL SECTION

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Office of Air and Waste Management
Office of Mobile Source Air Pollution Control
Alternative Automotive Power Systems Division
Ann Arbor, Michigan 48105

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ALTERNATIVE FUELS FOR AUTOMOTIVE TRANSPORTATION - A FEASIBILITY STUDY

VOLUME II - TECHNICAL SECTION

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Office of Air and Waste Management
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Alternative Automotive Power Systems Division
Ann Arbor, Michigan 48105

July 1974

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Publication No. EPA-460/3-74-012-b

PREFACE

This report is the result of a research team effort at the Institute of Gas Technology. In addition to the authors, the major contributors to the study were J. Fore, P. Ketels, W. Kephart, and K. Vyas.

This report consists of three volumes:

Volume I – Executive Summary

Volume II – Technical Section

Volume III – Appendices.

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LIST OF ABBREVIATIONS AND SYMBOLS*

AEC	Atomic Energy Commission
A. G. A.	American Gas Association
API	American Petroleum Institute
DCF	discounted cash flow
EEI	Edison Electric Institute
EPA	Environmental Protection Agency
DOT	Department of Transportation
FPC	Federal Power Commission
GNP	gross natural product
HTGR	high-temperature gas-cooled reactor
IGT	Institute of Gas Technology
JPL	Jet Propulsion Laboratory
LPG	liquefied petroleum gas
LSNG	liquefied substitute natural gas
MON	motor octane number
MRRD	minimum revenue requirement discipline
NO_x	oxides of nitrogen: NO (nitric oxide) and NO_2 (nitrogen dioxide)
RON	research octane number
SCF	standard cubic foot of gas (60°F, 30.00 in. Hg)
SLPG	substitute liquefied petroleum gas
SNG	substitute natural gas
SRC	solvent-refined coal
SWU	separative work units
10^6	million
10^9	billion
10^{12}	trillion
10^{15}	quadrillion
10^{18}	quintillion
UCLA	University of California at Los Angeles
USGS	United States Geological Survey

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* It is assumed that the reader is familiar with abbreviations for common units of measurement such as Btu (British thermal unit), bbl (barrel), psig (pounds per square inch gage), MW (megawatt), kWhr (kilowatt-hour), etc.

1. INTRODUCTION

1.1 Purpose and Objectives

The purpose of this study is to investigate potential solutions for the anticipated inability of domestic petroleum resources to supply adequate quantities of fuels for automotive transportation. Because of the unsatisfactory situation now developing in which the U.S. is becoming increasingly dependent on imported petroleum, the major emphasis in the selection of an alternative (non-petroleum-based) fuel is on its long-term availability from domestic sources. Economics, competition with other energy applications for limited energy resources, safety, handling, system efficiency, environmental impacts, and engine and fuel distribution system compatibility also are taken into account.

The objective of this study is to assess the technical and economic feasibility of alternative fuels for automotive transportation, specifically,

- Identification and characterization of potentially feasible and practical alternative fuels that can be derived from domestic, nonpetroleum energy resources
- Technical and economic assessments of the most promising alternative fuels for three specific time frames
- Identification of pertinent fuels and research data gaps and recommendations of alternative fuel(s) to best satisfy future U.S. automotive transportation requirements.

Working toward these objectives, we have generated a fuel selection methodology that can be applied to a potential alternative fuel. We have enlisted the factors of energy demand and supply, fuel availability, fuel synthesis technology, and certain physical, chemical, and combustion properties of the fuel. Apparent technology and information gaps that have bearing on a fuel's usefulness (for automotive purposes) are identified. This study provides background information for the development of U.S. energy programs pertaining to chemical fuels.

In recent years, the U.S. has realized that its projected supply of crude oil will not be sufficient to meet the expected increased demands of the future. In fact, recent projections of crude oil supply and petroleum fuel utilization indicate that, by about 1980, the domestic crude oil supply would not be sufficient for the total U.S. transportation energy demand (if it were so applied).

Because ground transportation, chiefly automobiles, trucks, and buses, consumes a majority of the transportation energy, these vehicles probably will have to find an additional energy source and possibly even a new fuel before the turn of the century.

1.2 Scope and Definitions

This study assesses the feasibility of alternative fuels for automotive transportation from domestic energy sources other than the conventional petroleum resource base. The petroleum resource base consists of crude oil, natural gas, and natural gas liquids (including LPG). Conventional gasoline from this petroleum resource base is the "reference" fuel. When possible, it is the basis for quantitative and qualitative comparisons.

In this study, "automotive transportation" refers to automobiles, trucks, and buses. The energy requirements for the remainder of the transportation sector are only incidental to this study; assessments are beyond the scope of this study. Accordingly, automotive energy demand is 75% (currently) of total transportation energy demand, or more than 18% of the total U.S. energy demand. This study primarily considers vehicles propelled by heat engines combusting chemical fuels. Electric vehicles – those storing and delivering energy electrochemically – are excluded from this study. However, vehicles that carry a chemical fuel and combust it in a fuel cell (to produce electricity for a motor) are included.

Fuel energy content, chemical and physical properties, and energy demand and supply quantities are presented in conventional (U.S.-English) engineering units. In Appendix A and as appropriate elsewhere, certain quantities also are listed in metric (SI) units. For engineering estimates, particularly in synthesis process calculations, high heating values are used. The high (or gross) heating value assumes that the water from combustion is condensed to yield latent heat that is included in the heat of combustion or in the enthalpy of a material stream for a process. However, in most instances, combustion of a fuel actually yields only the low (or net) heating value. (Water from combustion remains a vapor.) The fuel tabulations and comparisons in this report generally contain both values (as specified), but the low heating value is a more practical assessment of a fuel's energy content for automotive use.

This study is concerned with three time frames: near term, 1975-1985; mid term, 1985-2000; and far term, beyond 2000. Because of the uncertainties in future energy availability, technological advances, economics, and public policy, forecasts or projections beyond the near term are very difficult. The assumptions inherent in our energy demand and supply models are specified, and the reader can change the projections by changing the assumptions. Some of our projections have been made out to the year 2020 for illustrative purposes.

Two energy demand and supply projections (models) are detailed in this report for two purposes: 1) to present an illustration of the methodology of fuel selection and 2) to provide an optimistic possibility of domestic energy self-sufficiency as well as a pessimistic possibility of continued dependence on energy imports. The projections are not intended as models of energy allocation; rather, they are intended to show quantitatively the deficits and excesses that could exist in future time frames.

To apply the methodology of alternative fuel selection to a reasonable number of fuels, we have studied 16 fuels in this program. As possible energy sources for this synthesis, we have studied 12 potential domestic sources of energy. Table 1-1 lists these energy sources, four abundant auxiliary material sources, and the potential alternative fuels. The conventional crude oil and natural gas resource base is excluded. Also, we excluded any fuel that would produce significant amounts of combustion products not found in (unpolluted) air. In the potential automotive fuel list, "distillate oils" refer to the similar hydrocarbon mixtures, kerosene, diesel oil, and fuel oil (No. 1 or 2). Hydrazine is included as a fuel for fuel cells, and the coal would be a solvent-refined product (low in ash and sulfur content).

The selected fuels are evaluated in Sections 10 and 11 of this report, and the selections are made according to the methodology of Section 2. This methodology is applied to the energy and fuel information contained in Sections 3 through 9 and in Appendices A and B (Volume III). For convenience, we also present our selections, in order of preference, in Table 1-2.

Table 1-1. INITIAL-CONSIDERATION LIST

Energy Sources	Auxiliary Material Sources	Potential Automotive Fuels
Coal	Air (O_2, CO_2, N_2)	Acetylene
Shale oil	Rock (limestone)	Ammonia
Tar sands	Water	Carbon monoxide
Uranium and thorium	Land	Coal
Nuclear fusion		Distillate oils
Solar radiation		Ethanol
Solid wastes (garbage)		Gasolines (C_5-C_{10})
Animal wastes		Heavy oils
Wind power		Hydrazine
Tidal power		Hydrogen
Hydropower		LPG (synthetic)
Geothermal heat		Methanol
		Methylamine
		SNG
		Naphthas
		Vegetable oils

Table 1-2. SELECTED ALTERNATIVE FUELS

Near Term (1975-85)	Mid Term (1985-2000)	Far Term (Beyond 2000)
Gasoline from oil shale and water or coal and water	Gasoline from coal and water or oil shale and water	Gasoline from coal and water or oil shale and water
Distillate (diesel) oils from oil shale and water or coal and water	Distillate (diesel) oils from coal and water or oil shale and water	Distillate (diesel) oils from coal and water or oil shale and water
	Methanol from coal and water	Nuclear-based hydrogen (from water)
		Methanol from coal and water

2. FUEL SELECTION METHODOLOGY

2.1 Fuel Evaluation Procedure

Candidate alternative fuels are selected by evaluating the many potential fuels in terms of certain fundamental areas of concern, or general criteria. The concerns that we have identified are as follows:

- Adequacy of energy and material availability and competing demands for fuel
- The existence of known or developing fuel synthesis technologies
- Safety (toxicity) and handling properties of fuels
- Relative compatibility with contemporary fuel transport facilities and utilization equipment (tanks and engines)
- Severity of environmental impacts and resource depletion
- Fuel system economics (resource extraction, fuel synthesis and delivery, automotive utilization).

Some of the general criteria, for instance, the safety and handling aspects (toxicity, physical, and chemical properties), do not change with time. Others, such as the availability of a technology for fuel synthesis, may vary greatly during the three time frames of this study, so some assessments must be repeated. The different judgements for fuel selection must be as consistent as possible, and the criteria must be quantified when possible. How most of these general criteria are quantified into specific criteria and how other general criteria can be qualitatively used are discussed in this section of the report. The judgment process in which these general criteria are used is illustrated in Figure 2-1. Subsequent sections of this report present detailed explanations of the domestic natural resource base, energy demand and supply models, synthesis technology, fuel and engine compatibility, and fuel economics. Then the specific selection criteria are applied to the potential fuels to determine the best alternative fuel candidates.

According to the evaluation chart (Figure 2-1), certain background information must be assembled before the evaluation can proceed. This background information consists of the following items:

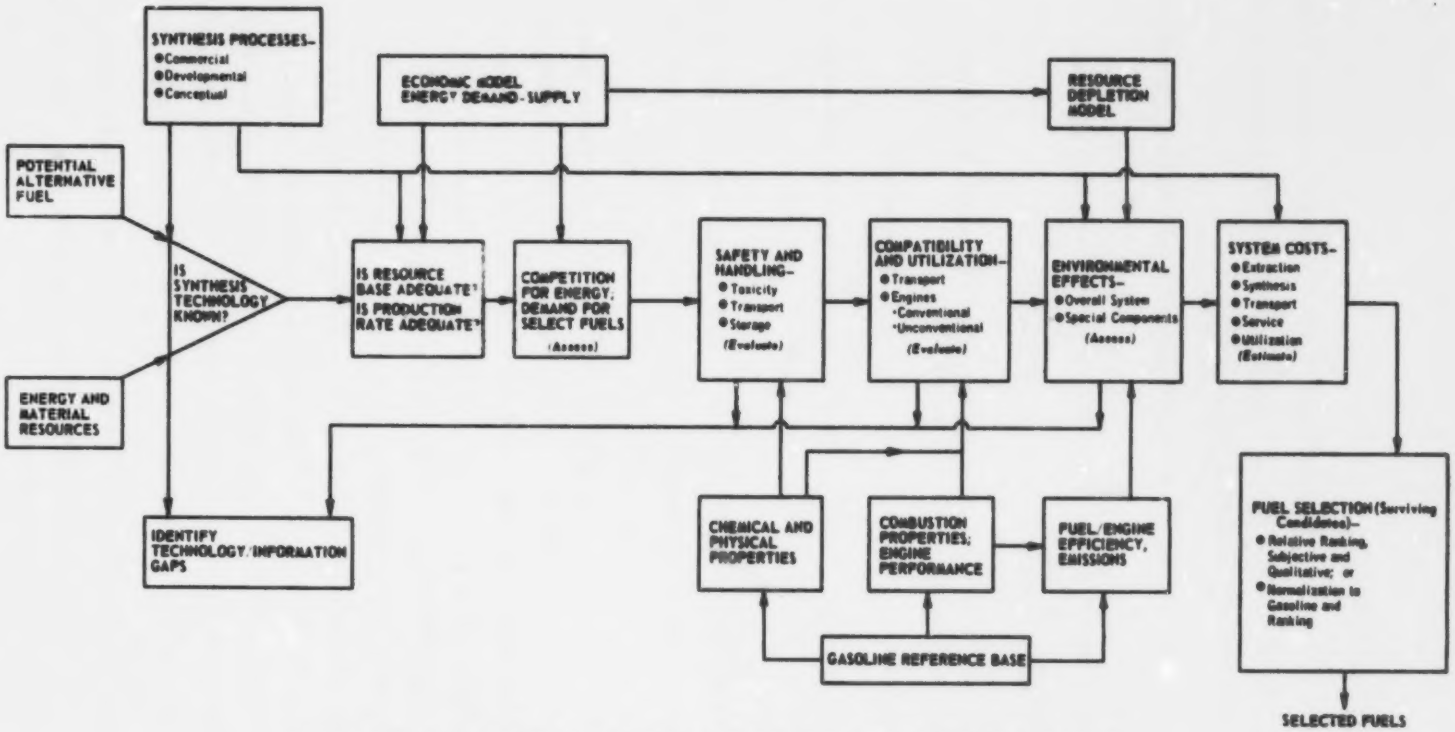
SYNTHESIS PROCESSES–
●Commercial
●Developmental
●Conceptual
ECONOMIC MODEL
ENERGY DEMAND-SUPPLY
RESOURCE DEPLETION MODEL
POTENTIAL ALTERNATIVE FUEL
IS SYNTHESIS TECHNOLOGY KNOWN?
ENERGY AND MATERIAL RESOURCES
IS RESOURCE BASE ADEQUATE?
IS PRODUCTION RATE ADEQUATE?
COMPETITION FOR ENERGY; DEMAND FOR SELECT FUELS
(Assess)
SAFETY AND HANDLING–
● Toxicity
● Transport
● Storage
(Evaluate)
COMPATIBILITY AND UTILIZATION–
● Transport
● Engines
·Conventional
·Unconventional
(Evaluate)
ENVIRONMENTAL EFFECTS–
● Overall System
● Special Components
(Assess)
SYSTEM COSTS–
● Extraction
● Synthesis
● Transport
● Service
● Utilization
(Estimate)
IDENTIFY TECHNOLOGY/INFORMATION GAPS
CHEMICAL AND PHYSICAL PROPERTIES
COMBUSTION PROPERTIES; ENGINE PERFORMANCE
FUEL/ENGINE EFFICIENCY, EMISSIONS
GASOLINE REFERENCE BASE
FUEL SELECTION (Surviving Candidates)–
● Relative Ranking, Subjective and Qualitative; or
● Normalization to Gasoline and Ranking
SELECTED FUELS

Figure 2-1. ALTERNATIVE FUEL EVALUATION METHOD

8-54-730

a. Quantitative information on the U. S. domestic energy (and material) resource base. This must include the conventional petroleum resource base for reference. Assured, reasonably assured, and speculative quantities are sought.

b. Energy demand and supply model(s). These models must be divided into market sectors to show deficits and excesses. The transportation sector is of prime concern.

c. Information on fuel synthesis processes. Needed are the availability of commercial processes, processes being developed, and conceptual processes for fuel synthesis from unconventional energy sources.

d. A bank of data on fuel properties — pertinent chemical, physical, combustion, and toxicity data. Also, prospects for fuel transport (handling) and fuel-engine compatibility and performance are needed. This also establishes the data for conventional gasoline, the reference fuel for this study.

e. A resource depletion model. This should integrate resource depletion from automotive requirements with energy.

The evaluation procedure begins with a determination of whether a given fuel can be synthesized by some process from an available energy (and material) resource. If not, but if subsequent evaluations are satisfactory relative to conventional gasoline (selection criteria met), a synthesis technology gap is identified. Other technology gaps that may be identified concern fuel transport or tankage, fuel-engine compatibility, and correctable environmental effects. The energy demand and supply model determines for the various time frames how much energy (fuel) is required and whether that fuel will be available for automotive use, considering competing demands from other (higher priority) sectors of the economy. These assessments are followed by determinations of fuel safety and handling, and compatibility and utilization. The overall resource depletion due to the synthesis and use of a fuel is calculated, and the environmental effects due to potential material pollutants are assessed (if quantitative determinations can be made). Finally, the fuel is given a rating relative to conventional gasoline by normalization of the quantitative data and the semiquantitative judgments. Thus, the fuel has a certain ranking relative to the other potential alternative fuels.

2.2 Resource Base

One prerequisite in the selection of an alternative automotive fuel is the determination of whether or not its domestic resources are adequate to support a substantial portion of the transportation demand for a period that allows major development and commercialization of a new industry. As a realistic benchmark and for consistency with economic procedures that are applied to industrial and commercial programs for which significant capital must be borrowed from sources external to the industry, 25 years has been chosen as this period. (A more detailed discussion about this 25-year period is given in Section 8.) Transportation demand is, of course, greater than automotive demand; hence, this criterion should be satisfactory in light of competition (from aircraft or railroads) for a commonly desired transportation fuel (e. g., distillate oils). If an alternative resource is not adequate, several alternative systems would be necessary. The term "substantial portion of the transportaion demand" is quantified by using the supply-demand projections of Model I. (See Section 4.) From this model, the transportation energy shortfalls vary between 28 and 34% annually between 1975 and 2000, as shown in Table 2-1.

Table 2-1. TRANSPORTATION ENERGY DEMANDS AND SHORTFALLS ACCORDING TO MODEL I

	1975	1980	1985	2000	2020
Demand, 10^{15} Btu	19.4	23.0	26.7	40.4	70.1
Shortfall, 10^{15} Btu (domestic)	6.4	7.4	7.4	13.8	41.7
Shortfall, % of demand	33	32	28	34	59

Integrating the Model I shortfall from 1975 to 2000 results in a total shortfall of about 215 X 10^{15} Btu, or an average annual shortfall of 8.6 X 10^{15} Btu. If one alternative fuel system (industry) is developed with the goal of domestic self-sufficiency, its output should be capable of eventually matching the shortfalls in Table 2-1. If two systems are developed, one might supply 90% of the shortfall, and the other, 10%. In this study, we are interested in alternative fuel systems that could have a major impact on the projected shortfalls. Therefore, as a benchmark, we have chosen one-half of the shortfall, or an integrated value of 108 X 10^{15} Btu (1975-2000), as the level of energy supply that must be potentially achievable by a viable and important alternative fuel system. This benchmark corresponds to about 15% of the total transportation energy demand. Hence, to be adequate, a new (unconventional) energy source should have the potential to supply 3-6 X 10^{15} Btu/yr of fuel between 1975 and 2000.

For renewable resources, the rate at which a resource becomes available for conversion is a practical limiting factor. To be adequate, this energy resource also must be able to meet about 15% of the transportation demand for 25 years. Energy sources that are limited by a lack of required materials, conversion efficiency (to a fuel), or other factors to a production rate of less than 3-6 X 10^{15} Btu/yr are considered inadequate.

From a multitude of sources, but principally the NPC's U.S. Energy Outlook,[1] we have assembled and categorized the domestic energy resource base in Section 3. For these resources, "assured" reserves are adjacent to current producing areas and have been measured with a high degree of certainty. "Reasonably assured" reserves are those that have a high probability of existing based on geological and other information similar to that found in areas currently being produced. "Speculative" reserves assume a high degree of optimism and could possibly fall into one of the former classifications by means of extensive exploration and development activity. We have chosen this definition of resource base because, for various resources, the documentation is adequate and categorization can be uniform. Use of other classifications, such as economically available (minable), would result in less consistency, because these quantities have been reported on different economic bases. Further, they are strongly affected by economic conditions, and they will vary unpredictably in future time periods.

2.3 Energy Model Effect

The need for an alternative fuel (to supplement conventional, petroleum-derived gasoline) is quantified by an energy demand and supply model that is postulated for future time frames. This model shows how much energy is needed and when it is needed for alternative fuels. Aside from the aspects of technology, environment, safety, compatibility, and system costs, this model sets limits on the energy supply shortfall. It is a selection criterion because it indicates for a given time frame that, after several "best qualified" fuel systems are selected, other (additional) fuel systems are not needed. The "best qualified" fuels are those that best meet all other criteria.

This study uses two energy models to bracket future supply and demand. They show the fuel requirements resulting from different assumptions about the effectiveness of conservation efforts, changing demand patterns, and the drive toward domestic self-sufficiency. These two models are described in detail in Section 4. A third model, not fully developed, also is contained in Section 4. This third model shows the effects of high fuel costs, extreme conservation, and federally legislated vehicle efficiency (fuel economy) on automotive fuel demand. The effect of these models on our selection criteria is to define the minimum resource base requirements and fuel production rates that are required in a particular time frame.

Some directly synthesized chemical fuels, SNG, and SLPG, are in prime demand by high-priority market sectors and are likely to be consumed by these sectors. Further, fuels derived from agricultural crops (ethanol and vegetable oils) must compete with food uses for the crop and with land for other crops (for food or timber or pasture).

For example, Model I projections of demand for SNG (from coal) and natural gas by all market sectors (except transportation), based on historical energy supply percentages, are shown in Table 2-2. From this assessment, not more than 1.4 X 10^{15} Btu of SNG will be available annually for automotive transportation.

Table 2-2. SNG (From Coal) PRODUCTION AND NATURAL GAS DEFICIT

	Gas Energy, 10^{15} Btu/yr			
Supply, Demand, Deficit	1975	1980	1985	2000
Projected Demand (Natural Gas+ SNG)	24.1	25.0	28.6	28.6
Projected Natural Gas Supply	24.5	24.6	28.0	22.0
Deficit	(0.4)	0.4	0.6	6.6
Model I SNG Production	0	1.0	2.0	8.0
Available for Automotive Use	0.4	0.6	1.4	1.4

2.4 Synthesis Technology

There are many ways (theoretically) to convert available energy and material resources into nonpolluting automotive fuels. Coal can be gasified into synthesis gas and ultimately into liquid and/or gaseous fuels by using suitable chemical processes. Oil shale and tar sands could be retorted, and the produced syncrude oil could be hydrogenated or hydrocracked into liquid fuels. Nuclear fuels can be converted into electric power and then into hydrogen by electrolysis of water. The hydrogen produced can be used in hydrocracking or hydrogenation of crude oil to make liquid fuels, or hydrogen itself can be used as an automotive fuel. Alcohol can be produced from plant materials by fermentation or from synthesis gas by catalytic reaction of CO and hydrogen. The nonmaterial energy sources, such as solar energy, winds, tides, geothermal heat, etc., can be converted into electric power. It may be possible to use heat energy derived from solar, nuclear, or geothermal sources as an input into chemical processing, for example, in the production of hydrogen from water or of methane from coal.

Most of these synthesis processes are discussed in more detail in Section 5 and in Appendix B. For purposes of evaluating and rating a process route for synthesis of a fuel, we have divided the processes into the following four classes:

1. The synthesis technology is probable. It has a reasonable probability of occurring during the time frames of this study. It is either a commercial process, or process components are available and a demonstration plant could be built.

2. The synthesis technology is possible. There is a possibility that it will be used during the time frames of this study. The process needs development work at the pilot-plant level. Prerequisite laboratory development has been completed.

3. The synthesis technology is speculative. There is an outside chance or a low probability that it could be used during the time frames of this study. The technology is in its conceptual stage and requires laboratory development and proof of practicality. A moderate technology gap exists.

4. The synthesis technology is unknown. A theoretical concept may exist, but proof of concept has not been demonstrated. A severe technology gap exists.

2.5 Fuel Properties

This subject encompasses physical, chemical, and combustion properties, safety (toxicity), transportability and storability, and compatibility with engines. Appendix A contains a listing of the pertinent chemical, physical, and combustion properties of 18 potential alternative fuels. Section 6 deals with the details of transportability, storability, and tankage and engine compatibility.

Safety assessments might be made by considering combinations of the combustion properties and toxicity of fuels. Combustion properties that are indicative of the likelihood of accidental fire are flash point, ignition energy, limits of flammability in air, and ignition temperature. Assigning a safety ranking to prospective fuels on the basis of this information is difficult. Obviously, gasoline and distillate oils can be handled safely; however, these fuels have very low lean flammability limits and low ignition temperatures. Gasoline also has the lowest flash point of any of the liquid fuels. Thus, we find only minor (insignificant) distinctions to be evident between fuels that are potentially safer than gasoline in terms of combustion when gasoline is handled safely in the reference system.

Toxicity is a different matter, and distinctions should be made. In our investigation, we have sought the following fuel concentrations in air: least amount for detectable odor, least amount causing eye irritation, least amount causing throat irritation, and maximum concentration allowable for prolonged (8-hr) exposure. Concentrations above this last value cause a variety of symptoms, differing with different fuels, but on the average, the effects would be deleterious and incapacitating. In some cases, these concentration values were not available. Fortunately, the data reported, for the most part, are consistent from source to source. Representative of these test results, and of great concern, is the concentration in air that is dangerous for prolonged exposure. By using the "toxicity ratio," which we define as the ratio of the 8-hour exposure concentration of the fuel in question to that of gasoline, the safety criterion can be quantified by:

$$\text{Toxicity ratio} = \left(\frac{\text{ppm fuel}}{\text{ppm gasoline}}\right)^{-1}$$

It would be inconvenient and expensive to introduce a fuel that has physical and chemical properties unsuited for the equipment now used for energy supply. The great economic incentive to retain existing facilities would have to be overcome. Fuels that can be handled in existing petroleum product distribution equipment have an enormous advantage at present.

At present, four separate transport systems handle four classes of fuels. About 10 X 10^{15} Btu are delivered as gasoline by the liquid-fuels-distribution system each year. The solid-fuel (coal) transmission system handles 600 X 10^{6} tons annually, or about 12 X 10^{15} Btu. Gaseous fuels, primarily natural gas, have their own pipeline system, which accounts for about 20 X 10^{15} Btu. The last class of distribution system, which moves condensable gases like LPG, is relatively small and would need a considerable (but possible) investment to accommodate the huge quantities of fuel required to supplement gasoline supplies.

The compatibility of each fuel is judged against the changes and additions to each of these four distribution systems that it would necessitate. The best situation allows the continued use of the liquid-fuel pipelines, trucks, and service stations system. A switch to one of the other three systems requires at least substantial new distribution equipment and service station facilities.

The transmission and distribution system required for an alternative is classed in one of four categories:

1. Probably compatible. The alternative fuel could use the present gasoline and/or distillate hydrocarbon (diesel fuel) transport and distribution system. No significant service station changes are required.

2. Possibly compatible. The alternative fuel has its own (large-scale) transport and distribution system, or it can use a present system with some modifications. Some new equipment (including service station facilities) is needed.

3. Compatibility is speculative. Essentially new equipment is needed for a workable system.

4. Incompatible. The fuel cannot be practically or safely used in any of the four major existing systems. New (sophisticated) equipment is needed that is beyond practicality.

We have estimated automotive tankage weights and volumes after consultation with manufacturers. Fuel energy content alone does not necessarily indicate the true weight of a fuel system. Because final tankage weights influence total vehicle weight and hence fuel consumption, we have calculated the tankage weights of alternative fuels at the energy equivalent of 20 gallons of gasoline. Fuels requiring a fuel storage system weighing in excess of 500 pounds are poor alternatives to gasoline. Tankage weights in the range of 200-500 pounds are considered good, and those in the range of 140-200 pounds (comparable to that of gasoline) are excellent. Tankage volume does not affect performance or fuel consumption, but can affect passenger and payload space. At 600 gallons, gaseous CO is unacceptable, and at 110 gallons, acetylene is very awkward. To quantify this criterion, we have used the tankage index defined as:

$$\text{Tankage index} = \left(\frac{\text{fuel tankage weight}}{\text{gasoline tankage weight}}\right) + \left(\frac{\text{fuel tankage volume}}{\text{gasoline tankage volume}}\right)$$

Just as it would be impractical to introduce a fuel in the near term that is incompatible with the present distribution system, it would be impractical to introduce a fuel that is incompatible with automotive power plants, present or planned. The compatibility of fuels with engines is judged on an arbitrary numerical scale. Details are presented in Sections 6 and 10. In the near-term time frame, fuels are judged for compatibility with conventional spark-ignited and diesel engines; for the mid term, stratified-charge engines are included; and for the far term, Brayton, Rankine, Stirling, and fuel cells are included along with conventional, stratified-charge, and diesel engines.

2.6 Environmental Effects

The potential for environmental damage associated with a fuel system stems primarily from resource extraction techniques, synthesis processes, and utilization methods. Types of pollutants as well as quantities depend on the type and efficiency of extraction, synthesis, and utilization. Furthermore, pollution depends on raw materials. For example, at a given production level, synthesis pollutants, such as sulfur, can vary by a factor of at least 5, depending on the type of coal used. Similarly, the volume of shale residue can vary by a factor of 3, depending on the grade of shale and the recovery efficiency of the process. Note that the amount of resource depletion (for automotive transportation purposes) depends on engine efficiency, which, e.g., could vary by a factor of 1.5 (Wankel versus diesel).

In general, we have not developed pollution or resource depletion into general selection criteria because efficiencies, emissions, and performances for the various system components are generally not known with sufficient precision. In many cases, estimates of these would be conjecture. However, some partial conclusions are possible, and we present pertinent information in Section 7.

2.7 Fuel System Economics

To further evaluate alternative fuels, we have applied a costing procedure to the potential fuel systems. This method sums the calculated costs of resource extraction and synthesis, the costs of refining or liquefying, and the costs of transmission and distribution. This procedure yields a delivered fuel cost ($/Btu). As with environmental effects, these costs are only part of the system. A complete fuel selection criterion would include the cost per mile driven by the consumer and attributable to a given fuel. Such calculations entail knowledge of the fuel-engine efficiency and vehicle weights as well as the fuel cost at the service station-vehicle interface. These calculations are complex and tenuous because they involve a mix of measured, approximated, and assumed engine efficiencies, vehicle weights, and attendant fuel consumption. These considerations are beyond the scope of this report.

The determination of fuel system costs has been done in two phases. An initial "rough cut," using published estimates of resource extraction and synthesis costs, was done first. Transmission and distribution costs for similar fuels or chemicals were used. For the several attractive candidate fuels (those ranking most favorably with respect to gasoline), a second, detailed determination of costs was made. Section 8 and Appendix B contain pertinent details. The cost of a fuel is itself quantified; as a criterion, it has been normalized by dividing by the cost of conventional gasoline.

2.8 Technology and Information Gaps

In this study, a "technology gap" is defined as a technical difficulty that makes an otherwise acceptable fuel impractical but that might yield to intensive research and development. For instance, hydrogen is perhaps the cleanest and most efficiently combusted fuel, and its production is commercially feasible (although expensive). Today, however, there are no satisfactory methods for vehicle storage of hydrogen. Unless this problem is solved, hydrogen will not be used as an alternative automotive fuel. LPG also has a technology gap. The fuel can be transported, stored, and utilized satisfactorily, and vast raw materials are accessible (coal and water). However, no (catalytic) process has been found that will make principally LPG from synthesis gas (a mixture of hydrogen and carbon monoxide), which is the first step in clean fuel-from-coal processes.

We have further qualified technology gaps as serious or moderate. The existence of a serious technology gap eliminates a fuel from general supplemental use (as an alternative fuel) before the year 2000. This is necessitated by the lead times required for research, development, prototype achievement, demonstration, operation and testing (plant or product), and production plant (or industry) construction and operation. Less serious (moderate) technology gaps, such as a fuel storage technique or an emission control device, will eliminate a fuel for the near term (before 1985).

As the study progressed, we encountered another type of gap: information. In some cases, the data necessary to properly evaluate the potentials of candidate fuels do not exist, are imprecise and subject to controversy, or are subject to restricted access. In most cases, we have identified these "information gaps" and discussed their implications.

2.9 Reference Cited

1. National Petroleum Council, U.S. Energy Outlook: A Report of the National Petroleum Council's Committee on U.S. Energy Outlook. Washington, D.C., December 1972.

3. U.S. DOMESTIC RESOURCE BASE

The present U.S. domestic energy resource base of all nonrenewable fuels, both fossil and nonfossil, is in the range of 91-139 X 10^{18} Btu. The lower end of the estimate is based upon uranium consumption in burner reactors without plutonium recycle, and the higher end of the estimate takes into account the development and implementation of the breeder reactor. The domestic resources are presented in Table 3-1 in conventional units and in Table 3-2 in Btu equivalents. These tables are derived from raw data that are contained in the NPC report[10] and in a variety of other sources,[1,2,6,9,12,13] and have been subclassified into reserves that are "assured," "reasonably assured," and "speculative."

Many difficulties were encountered in assembling Tables 3-1 and 3-2. Uranium reserves, expressed in tons, can be converted to thermal energy, expressed in Btu's, at efficiencies that differ greatly depending on whether or not the breeder reactor is developed. Both estimates for uranium are presented in Table 3-2. Reserves of thorium are substantial; however, technology for its conversion to a usable form of energy is not yet assured. Therefore, thorium data were omitted from Table 3-2 even though they appear in Table 3-1. Nuclear fusion data were omitted from both tables because the technology necessary for conversion to useful energy does not yet exist.

Hydropower, solar energy, wind, geothermal energy, wastes, and tidal power are renewable energy resources, so they are shown as an annual quantity. The other energy forms are nonrenewable; that is, they cannot be replaced once they are extracted from their natural state. Solar energy is a renewable resource that could be classified as either assured or speculative. The quantity given in Tables 3-1 and 3-2 relates to the total quantity of direct solar energy falling on the land mass of the contiguous 48 states. The quantity is "assured," although all of it will not be available for conversion to transportable energy or fuels because the entire land mass will not be covered with solar collectors. Most of the wind power available to the U.S. would result from solar radiation falling on the ocean surface and not on the land mass. Thus, any detailed comparison of the quantities given in Table 3-2 must be carried out with some degree of caution. The following is a brief discussion of the location and prospects for development of each resource listed in Tables 3-1 and 3-2.

Table 3-1. U.S. ENERGY RESOURCE BASE IN CONVENTIONAL UNITS

Resource	Units	Assured	Reasonably Assured	Speculative	Total
Hydrocarbons (Nonrenewable)					
Coal[a]	10^{12} tons	1.56	1.65	--	3.21
Crude Oil[b]	10^{9} bbl	36.3	227.0	209.0	472.3
Natural Gas[c]	10^{12} CF	266.0	384.0	496.0	1146.0
Natural Gas Liquids[d]	10^{9} bbl	6.8	--	--	6.8
Oil Shale[e]	10^{9} bbl	34.0	281.0	1466.0	1781.0
Tar Sands[f]	10^{9} bbl	23.5	--	--	23.5
Nuclear					
Uranium[g]	1000 tons	520.0	1000.0	--	1520.0
Thorium[h, i]	1000 tons	46.0[h]	249.0	--	295.0
Nuclear Fusion	--	--	--	--	--
Renewable, Annual					
Hydropower[j]	10^{9} kWhr/yr	530.0	--	--	530.0
Geothermal[k]	10^{15} Btu/yr	5.6	2.8	--	8.4
Solar Energy (direct)[m]	10^{15} kWhr/yr	14.4	--	--	14.4
Tidal Energy[n]	10^{9} kWhr/yr	--	1.8	--	1.8
Wind Power[o]	10^{15} Btu/yr	5.4	--	--	5.4
Municipal Wastes[p]					
1975 (5.4 lb/person/day)	10^{9} lb	422.0	--	--	422.0
1985 (7.0 lb/person/day)	10^{9} lb	602.0	--	--	602.0
Animal Feedlot Wastes[q]					
1975 Manure	10^{6} tons	332.0	--	--	332.0
1985 Manure	10^{6} tons	452.0	--	--	452.0

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Table 3-1. Cont. U.S. ENERGY RESOURCE BASE IN CONVENTIONAL UNITS

[a] These resource classifications were made to establish some uniformity and to provide a basis for direct comparison of the availability of the various energy resources.

Coal: Assured – reserves that are mapped and explored with 0-3000 ft of overburden; recovery factors not applied. Reasonably Assured – reserves that are in unmapped and unexplored areas with an overburden of 0-6000 ft.

[b] Crude oil: Assured – reserves of crude oil that have been discovered but not yet produced; often referred to as "proved reserves." Reasonably Assured – based upon extensive seismic and geological work performed in areas within or adjacent to current producing areas. Speculative – reserves estimates based on geological characteristics of nonproducing areas; economic recoverability not considered.

[c] Natural Gas: Assured – reserves both drilled and undrilled; undrilled reserves located so close to the drilled reserves that every reasonable probability exists that they will be recovered when drilled and may be associated or nonassociated. Reasonably Assured – based on new discoveries in previously productive formations that are distinctly different from existing fields. Speculative – the most uncertain of new supplies, attributable to new field discoveries in formations or provinces not previously productive.

[d] Natural Gas Liquids: reserves based upon the historical ratio of natural gas to natural gas liquid discoveries. Applied to "assured" reserves of natural gas only.

[e] Oil Shale: Assured – resources satisfying the basic assumption limiting resources to deposits at least 30 feet thick and averaging 30 gal/ton of shale by assay; those that are assured are a more restrictive cut of these reserves and indicate the portion that would average 35 gal/ton over a continuous interval of at least 30 feet (Class I resource). Reasonably Assured – those resources yielding 30-35 gal/ton over a continuous interval in deposits 30 ft deep; regions of occurrence are poorly defined and/or not favorably located (Class I and III resources). Speculative – resources that are poorly defined ranging down to 15 gal/ton yield, not of current commercial interest (Class IV resources).

[f] Tar Sands: Assured, small quantities of tar sands lie within the U.S., but commercial development is unlikely.

[g] Potential resources are reasonably assured.

[h] Assured, recovered as a by-product.

[i] Reasonably assured if recoverable from deposits about 0.1% thorium oxide.

[j] 281 billion kWhr developed; additional 249 billion kWhr available.

[k] Localized hydrothermal systems down to 6 miles deep; 1% of total equals annual production.

[m] Average over 24-hr period and four seasons, 17W/sq ft over entire U.S. land area.

[n] Passamaquoddy Bay, Me.; assumed to operate 4380 hours/yr.

[o] 10 times the projection of Heronemus for ocean wind generators for New England.

[p] Collected municipal solid wastes including household, commercial, industrial, construction, and demolition.

[q] Manure (dry basis) from animal feed lots (90% from cattle). In 1975, 130 X 10^6 head; 1985, 177 X 10^6 head; 70 lb manure (wet) per head per day.

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Table 3-2. U.S. ENERGY RESOURCE BASE IN Btu EQUIVALENTS

Resource	Btu/Unit	Assured	Reasonably Assured	Speculative	Total	% of Total A*	% of Total B*
		10^{15} Btu					
Hydrocarbon							
Coal	24 million/ton	37,400	39,600	--	77,000	84.3	55.1
Crude Oil	5.8 million/bbl	210	1,317	1,212	2,739	3.0	2.0
Natural Gas	1032/CF	274	396	512	1,182	1.3	0.9
Natural Gas Liquids	4.0 million/bbl	27	--	--	27	Negl	
Oil Shale	5.4 million/bbl	116	1,517	7,916	9,549	10.5	6.9
Tar Sands	5.4 million/bbl	127	--	--	127	0.1	0.1
Nuclear							
Uranium							
In Burner Reactors Without Plutonium Recycle	400 billion/ton	250	400	--	650	0.7	--
In Breeder Reactors	300 trillion/ton	18,750	30,000	--	48,750	--	34.9
Throium	--	--	--	--	--		
Nuclear Fusion	--	--	--	--	--		
Total Nonrenewable		38,403 to 56,903	43,506 to 73,106	9,640	91,549 to 139,649	99.9	99.9
Renewable, Annual		10^{15} Btu/yr					
Hydropower	3414/kWhr	1.8	--	--	1.8		
Geothermal	--	5.6	2.8	--	8.4		
Solar Energy	17 W/sq ft	49,056	--	--	49,056		
Tidal Energy	--	--	Negl	--	--		
Wind Power	--	--	5.4	--	5.4		
Municipal Wastes							
1975	4580/lb	1.9	--	--	1.9		
1985	4740/lb	2.9	--	--	2.9		
Animal Feedlot Wastes							
1975	7500/lb	5.0	--	--	5.0		
1985	7500/lb	6.8	--	--	6.8		
Total Renewable Annual		49,080.0	8.2	--	49,088.2		

* A = uranium in burner reactors without plutonium recycle.

* B = uranium in breeder reactors.

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Each resource has been categorized according to its natural occurrence and most probable end use. Three categories were selected: hydrocarbon reserves, nuclear reserves, and renewable resources. Hydrocarbon reserves comprise coal, crude oil, natural gas and natural gas liquids, oil shale, and tar sands. These resources typically are naturally occurring and are nonrenewable after extraction and use. Nuclear reserves comprise uranium and thorium, which are naturally occurring metal ores that must be reduced before they can be used. As in the case of hydrocarbon resources, nuclear reserves are nonrenewable. The last category, renewable resources, comprises hydropower, geothermal heat, direct solar energy, wind power, waste materials, and tidal power. Based on historical patterns, these resources are expected to be available at an almost constant annual rate, with the exception of municipal and animal feedlot wastes, which increase somewhat with time.

3.1 Hydrocarbon Reserves

3.1.1 Coal

The total quantity of coal available within the U.S. is estimated to be 3.21 trillion tons, based on a report prepared by the USGS.[1] This quantity is broken down as follows:

	10^{12} tons
Mapped and Explored 0-3000 ft overburden	1.56
Probable Addition, Unmapped and Unexplored Areas	
0-3000 ft depth	1.31
3000-6000 ft depth	0.34
Total	3.21

The quantity of coal classified as mapped and explored above, 1.56 trillion tons, is shown in Figure 3-1 as a percentage distribution by depth with three categories of certainty. The block defined by the broken lines is equivalent to 25% of the mapped and explored reserves, 394 billion tons, and is termed in the coal industry as "measured" and "indicated" reserves. This can be further broken down into coal mined underground (349 billion tons) and surface-mined coal (45 billion tons).

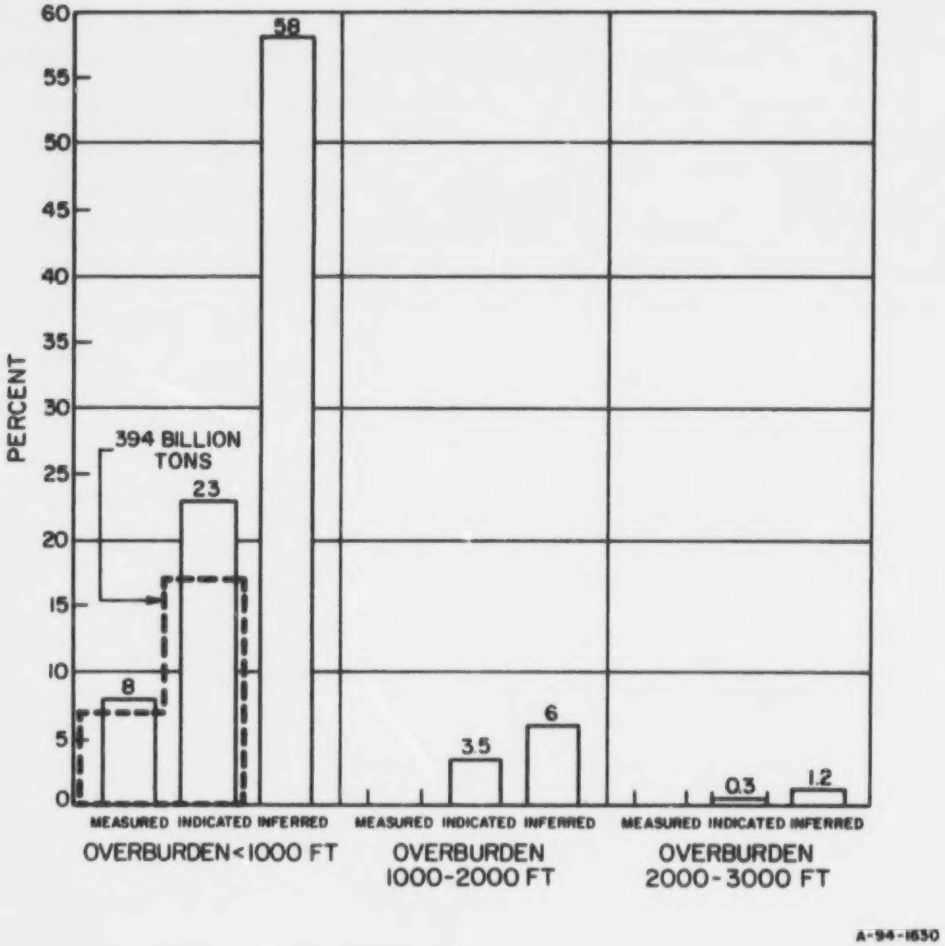

Figure 3-1. ESTIMATED MAPPED AND EXPLORED COAL RESOURCES IN THE U.S. (Total Shown, 1.56 Trillion Tons) (Source: Ref. 10)

The 349 billion tons of underground coal have been further categorized as "economically available reserves" by the exclusion of underground lignite, bituminous, and subbituminous seams of intermediate and thin thickness, leaving a total of 209.2 billion tons. To estimate recoverable underground reserves, a recovery factor of 50%, based on present underground mining methods, could be used. As a result, the quantity of "economically recoverable" underground reserves would be reduced to 104.6 billion tons. The resource quantity has been related to the 1970 rate of production to illustrate reserve life in terms of growth rates of 0, 3, and 5% annually. This is shown in Table 3-3.

Table 3-3. UNDERGROUND COAL RESERVES AND PRODUCTION (Minable by Underground Mining Methods) (Source: Ref. 10)*

	Billions of Tons				Life of Recoverable Reserves at % Growth Rate (Years)		
Region	Remaining Measured and Indicated Reserves*	Economically Available Reserves†	Recoverable Reserves‡	1970 Production (Millions of Tons)	0%	3%	5%
1	92.7	67.1	33.5	145.8	230	69	50
2	9.1	9.1	4.6	N.A.	–	–	–
3	83.1	59.5	29.7	52.3	568	96	68
4	34.5	24.4	12.2	95.0	129	52	40
5	21.9	13.3	6.7	8.6	774	106	74
6	1.6	.6	.3	9.1	35	23	20
Other	106.3	35.2	17.6	N.A.	–	–	–
Total §	349.1	209.2	104.6	338.8	309	80	58

* Bituminous, subbituminous and lignite in seams of "intermediate" or greater thickness and less than 1,000 feet overburden (see Figure 50).

† Excludes lignite and "intermediate" thickness seams of bituminous and subbituminous coal.

‡ Based on 50 percent recovery of economically available reserves.

§ May not add correctly due to rounding.

The map in Figure 3-2 shows each of the geographical regions where coal is mined underground, and Table 3-3 shows the coal reserves in each region. A major changeover to a technique such as long-wall mining could result in a higher recovery factor (as much as 75%) and increase the recoverable reserves total significantly. Hence, "economically recoverable" quantities (of coal or any resource) are subject to great change in the future as economics and technology change.

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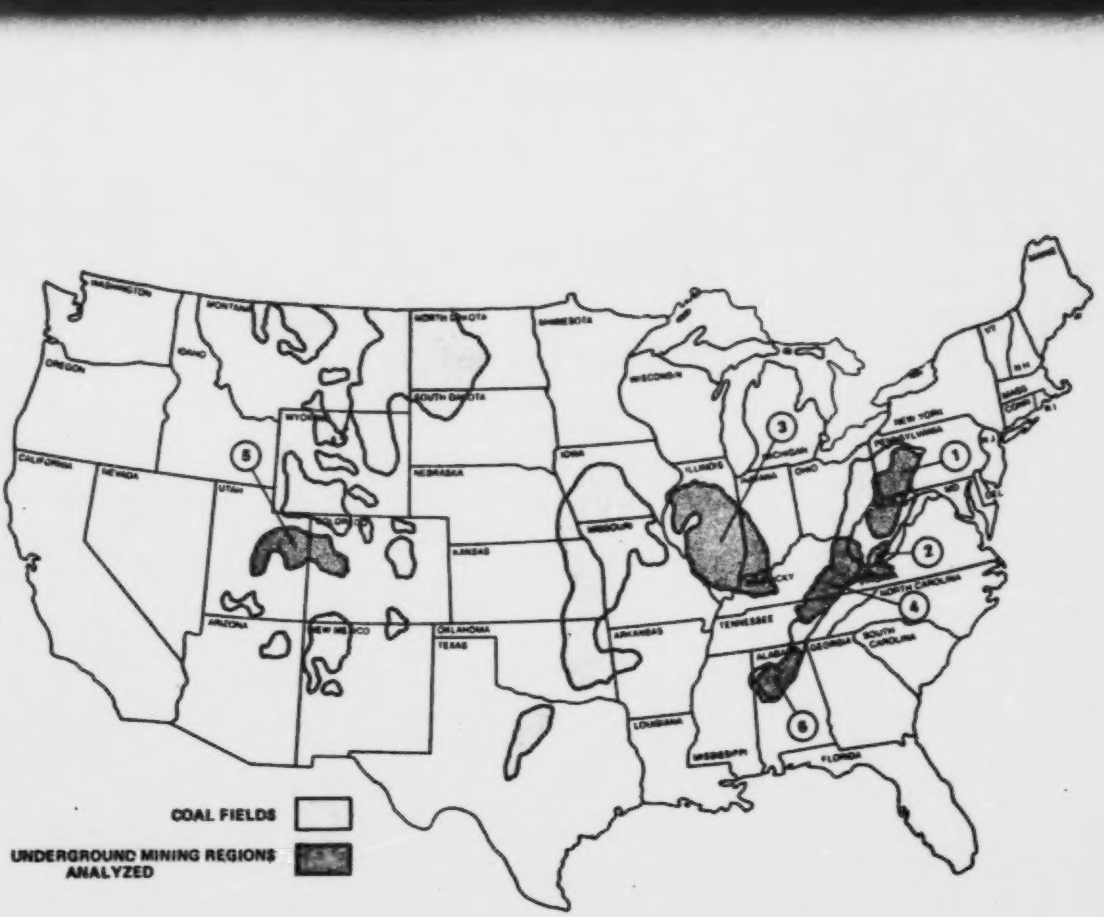
COAL FIELDS
UNDERGROUND MINING REGIONS ANALYZED
1
2
3
4
5
6
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
ARIZONA
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
NEW YORK
PENNSYLVANIA
MD
VT
NH
MASS
CONN
RI
MAINE

Figure 3-3. MAJOR SURFACE-MINING REGIONS OF U.S. COAL FIELDS (See Table 3-4) (Source: Ref 10)*

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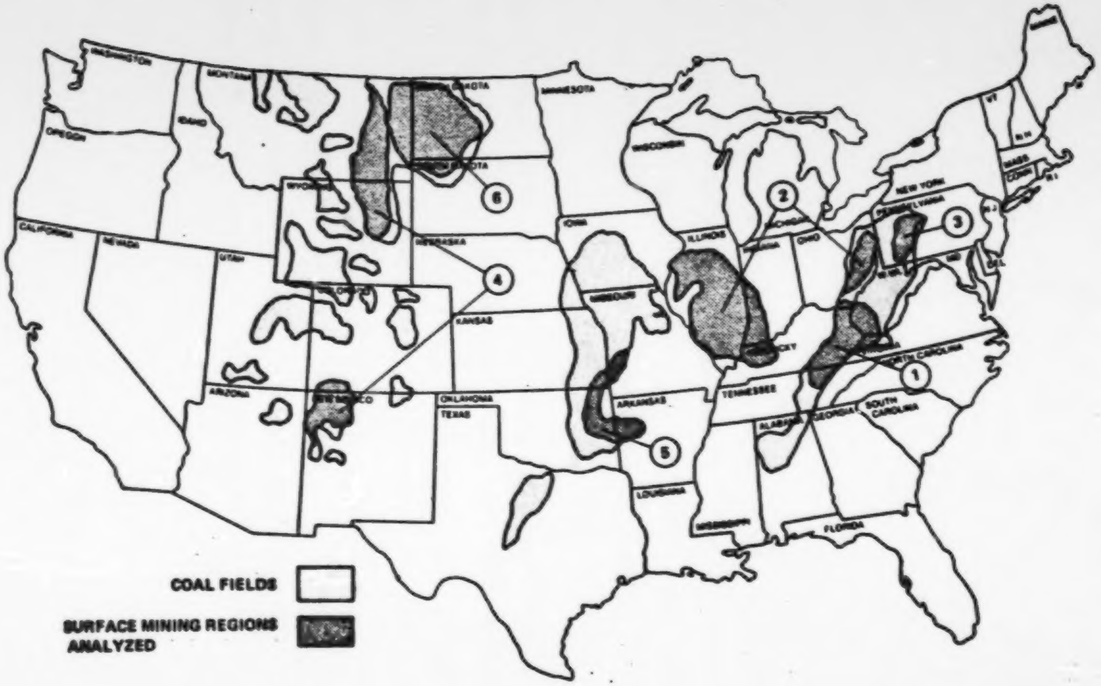
COAL FIELDS
SURFACE MINING REGIONS ANALYZED
1
2
3
4
5
6
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
ARIZONA
NEW MEXICO
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
WISCONSIN
IOWA
MISSOURI
ARKANSAS
LOUISIANA
ILLINOIS
INDIANA
OHIO
MICHIGAN
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
PENNSYLVANIA
NEW YORK
VT
N.H.
MASS
CONN
R.I.
MAINE

Figure 3-2. MAJOR UNDERGROUND MINING REGIONS OF U.S. COAL FIELDS (See Table 3-3) (Source: Ref. 10)*

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Recoverable surface-mined coal reserves are shown in Table 3-4, corresponding to the regions shown in Figure 3-3.

Table 3-4. SURFACE COAL RESERVES AND PRODUCTION (Minable by Surface Mining Methods) (Source: Ref. 10)*

Region	Recoverable Reserves (Billions of Tons)	1970 Production (Millions of Tons)	Life of Reserves at % Growth Rate (Years)		
			0%	3%	5%
1	4.2	101.2	42	27	23
2	5.6	91.0	62	36	29
3	0.8	25.1	32	23	19
4	23.8	19.1	1,246	122	85
5	1.6	8.3	193	65	48
6	2.1	5.6	375	85	62
Other	6.9	13.8	500	95	67
Total	45.0	264.1	170	61	46

(A recovery factor is not applied in the same manner as in the case of underground mining, because in most cases it is in excess of 90%.) As in the case of underground coal, the life of surface reserves is related to 1970 production levels at annual growth rates of 0, 3, and 5% in Table 3-4.

Within existing mapped and explored areas are thick coal beds under less than 1000 feet of overburden that are considered to be potentially available. For this study, a coal resource base with an overburden of 3000 feet or less is classified as "assured." All other coal resources are classified as "reasonably assured." This categorization is shown in Figure 3-4. We use this classification of the U.S. coal resource base, for comparison, to be as consistent as possible with the potential availability of other resource bases for supporting an alternative fuel system.

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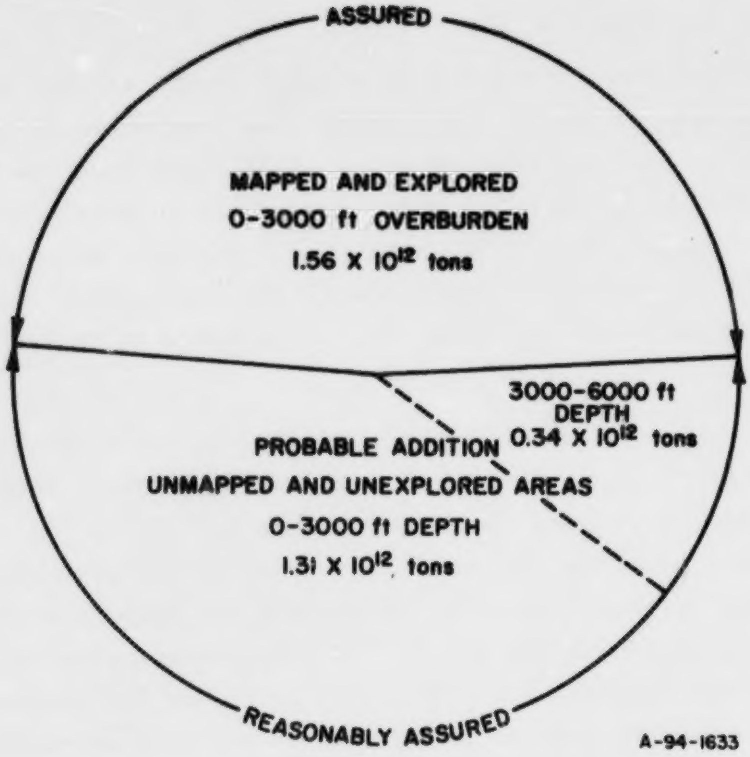
ASSURED
MAPPED AND EXPLORED
0-3000 ft OVERBURDEN
1.56 X 10¹² tons
3000-6000 ft
DEPTH
0.34 X 10¹² tons
PROBABLE ADDITION
UNMAPPED AND UNEXPLORED AREAS
0-3000 ft DEPTH
1.31 X 10¹² tons
REASONABLY ASSURED
A-94-1633

Figure 3-4. CATEGORIZATION OF THE U.S. COAL RESOURCE BASE

3.1.2 Crude Oil

Although a number of investigators have made estimates of the total quantity of oil in place in the U.S., we have chosen to present an estimate that was made in connection with the recent energy study by the National Petroleum Council.[10] This estimate is shown in Table 3-5. The regions are shown in Figure 3-5.

The NPC estimates are based on a prior study, entitled the Future Petroleum Provinces of the United States,[8] and some of the numbers have been revised to reflect 1972 estimates. Table 3-5 from the latter report is shown here to provide some indication of the geographical location of future oil supplies; recent NPC revisions[10] have been included where applicable. Of the volume of future remaining discoverable crude oil, approximately 42%, or 160 billion bbl, is believed to be located in offshore areas.

The NPC reports a total of 810 billion bbl of oil ultimately discoverable in the U.S., including Alaska. Of this total, more than half, or 425 billion bbl, have been discovered, while 385 billion bbl remain to be identified. However, the total quantity of proved recoverable crude reserves (the "assured" quantity) in the U.S. at present amounts to approximately 36 billion bbl of oil. The remaining reserves of original oil-in-place are divided by the NPC into 227 X 10^9 barrels as possible-probable (reasonably assured) and 209 X 10^9 barrels as speculative. The quantities of the crude oil resource base that we categorize as assured, reasonably assured, and speculative are presented in Figure 3-6.

3.1.2.1 Lower 48 Oil Supply

The onshore areas of the Lower 48 States contain approximately 70% of the total ultimate discoverable oil-in-place. An estimated 31% of this remains to be discovered. In areas such as the mid-continent region, which has already been thoroughly explored, only 6.4 billion bbl, or 7%, of the ultimate reserves remains to be discovered. However, in regions such as the Rocky Mountains, as much as 65 X 10^9 bbl of oil are potentially discoverable.

Table 3-5. OIL-IN-PLACE RESOURCES
(Source: Ref. 10)*

		Billion Barrels		Remaining Discoverable Oil-in-Place	
Region		Ultimate Discoverable Oil-in-Place	Oil-in-Place Discovered to 1/1/71	Billion Barrels	% of Ultimate
Lower 48 States–Onshore					
2	Pacific Coast	101.9	80.0	21.9	21.5
3	Western Rocky Mtns.	43.6	5.8	37.8	86.7
4	Eastern Rocky Mtns.	52.4	23.9	28.5	54.3
5	West Texas Area	151.6	106.4	45.2	29.8
6	Western Gulf Coast Basin	109.0	79.7	29.3	26.9
7	Midcontinent	63.0	58.4	4.6	7.3
8–10	Michigan, Eastern Interior and Appalachians	36.5	30.5	6.0	16.4
11	Atlantic Coast	3.8	0.2	3.6	94.7
	Total	561.8	384.9	176.9	31.5
Offshore and South Alaska					
1	South Alaska Including Offshore	26.0	2.9	23.1	88.8
2A	Pacific Ocean	49.6	1.9	47.7	96.2
6A	Gulf of Mexico	38.6	11.5	27.1	70.0
11A	Atlantic Ocean	14.4	0.0	14.4	100.0
	Total	128.6	16.3	112.3	87.3
Total United States (Ex. North Slope)		690.4	401.2	289.2	41.9
Alaskan North Slope					
	Onshore	72.1	24.0	48.1	66.7
	Offshore	47.9	0.0	47.9	100.0
	Total	120.0	24.0	96.0	80.0
Total United States		810.4	425.2	385.2	47.5

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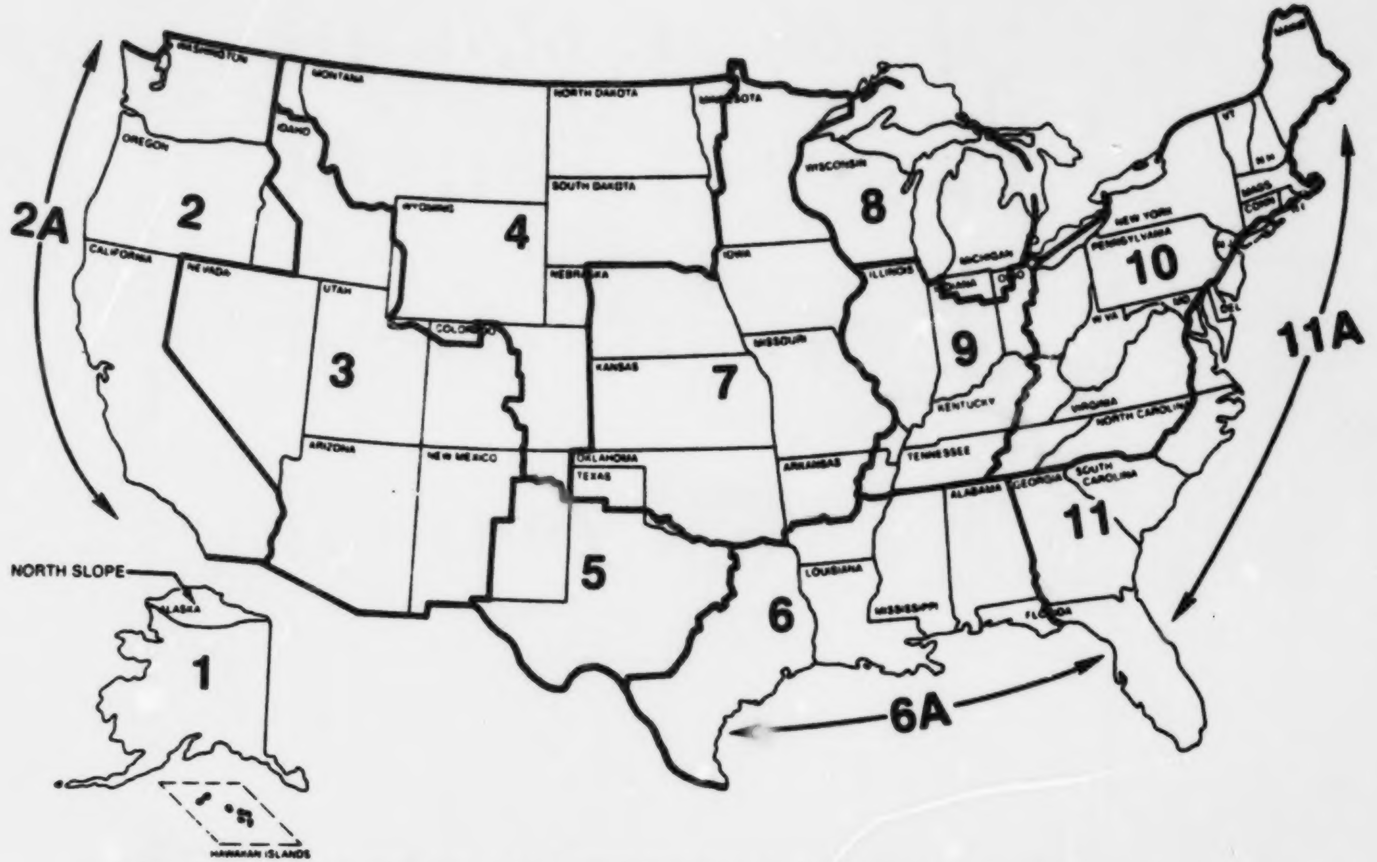
2A
2
1
3
4
5
6
6A
7
8
9
10
11
11A
NORTH SLOPE
ALASKA
HAWAIIAN ISLANDS
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
COLORADO
ARIZONA
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
W VA
PENNSYLVANIA
NEW YORK
MD
DEL
VT
NH
MASS
CONN
MAINE

Regional Boundaries: Region 1 – Alaska and Hawaii, except North Slope; Region 2 – Pacific Coast States; Region 2A – Pacific Ocean, except Alaska; Region 3 – Western Rocky Mountains; Region 4 – Eastern Rocky Mountains; Region 5 – West Texas and Eastern New Mexico; Region 6 – Western Gulf Basin; Region 6A – Gulf of Mexico; Region 7 – Midcontinent; Region 8 – Michigan Basin; Region 9 – Eastern Interior; Region 10 – Appalachians; Region 11 – Atlantic Coast; Region 11A – Atlantic Ocean.

Figure 3-5. PETROLEUM PROVINCES OF THE U.S. (Source: Ref. 10)*

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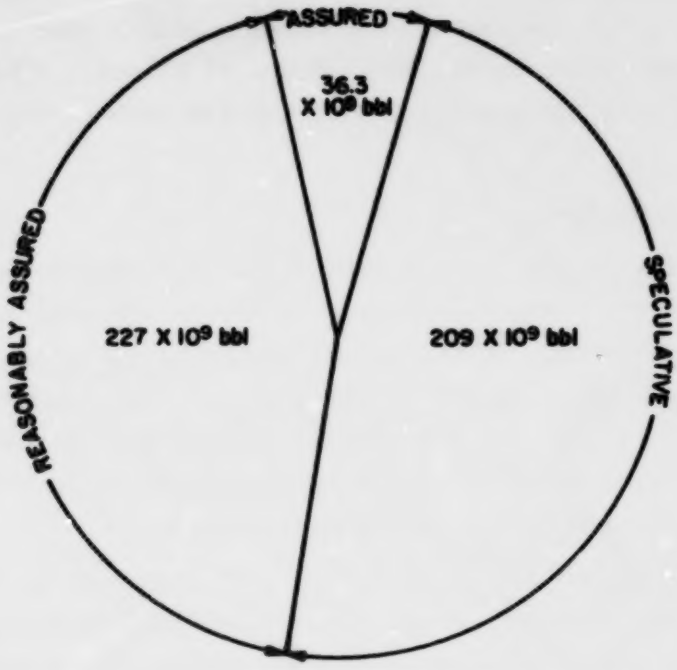


Figure 3-6. CATEGORIZATION OF U.S. CRUDE OIL RESOURCE BASE

3.1.2.2 Offshore Oil Supply

Table 3-5 also shows that the ultimate discoverable oil-in-place estimated in the offshore regions of the U.S. and the Gulf of Alaska amounts to about 129 billion bbl, of which only 16 billion bbl have been discovered as of January 1971. Thus, about 112 billion bbl remain to be discovered in these offshore areas. By 1985, an estimated 50% of the domestic oil supply will come from offshore areas.

3.1.2.3 Alaskan Oil Supply

The ultimate discoverable oil-in-place on the Alaskan North Slope, both offshore and onshore, amounts to approximately 120 billion bbl. Only 24 billion bbl are classed as discovered, leaving an additional 96 billion bbl as potentially discoverable on the North Slope. However, although the area around Prudhoe Bay has been partially explored, the Naval

Petroleum Reserve to the west is generally believed to contain larger reserves of oil and gas. Note that the 5-year delay in building an Alaskan pipeline has created a corresponding moratorium on further drilling and exploration on the North Slope of Alaska. This work is now being resumed with the assurance that pipeline construction is finally under way.

3.1.3 Natural Gas

The estimated potential gas supply of the U.S. reported by the NPC is 1178 trillion CF. This estimate is based on the work of the A.G.A.'s Potential Gas Committee in its report, Potential Supply of Natural Gas in the United States (as of December 31, 1970).[13] Since publication of the NPC report, the committee has revised its estimate of potential gas supply downward to 1146 trillion CF (as of December 31, 1972). This latter estimate is the basis for the following discussion.

The future potential supply of natural gas is defined by the committee as the prospective quantity of gas yet to be found, exclusive of proved reserves. The future potential supply is further divided into the following categories, the sum of which is the total future potential supply:

- Probable. The most assured of new supplies resulting from existing gas fields.
- Possible. These supplies are less assured than those that are probable and are derived from new discoveries in previously productive formations. These new fields are distinctly different from existing fields.
- Speculative. These are the most uncertain of new supplies and are attributable to new field discoveries in formations or provinces not previously productive. A summary of the PGC estimates is shown in Table 3-6.

Within the NPC study,[10] the volume of past natural gas production is combined with current proved reserves and potential supply to arrive at a quantity of "ultimate gas discoverable." The cumulative quantity of gas produced and proved reserves, as of December 31, 1972, then are subtracted from the ultimate gas discoverable, and the result is referred to as the future potential supply. This calculation, based on December 31, 1972, estimates, is as follows:

Table 3-6. SUMMARY OF ESTIMATED POTENTIAL SUPPLY OF NATURAL GAS IN U.S. BY DEPTH INCREMENTS AS OF DECEMBER 31, 1972

	Area Totals			
	Probable	Possible	Speculative	Total
	10^{12} CF at 14.73 psia and 60°F			
Onshore (Drilling Depth)				
0-15,000 ft	121	153	139	413
15,000-30,000 ft	33	45	59	137
Subtotal	154	198	198	550
Offshore (Water Depth)				
0-600 ft	58	74	71	203
600-1500 ft	†	18	9	27
Subtotal	58	92	80	230
Total for 48 States	212	290	278	780
Alaska *	54	94	218	366
Total U.S.	266	384	496	1,146

* Not available by depth increments.

† Less than 1 X 10^{12} CF.

		10^{12} CF
Ultimately Discoverable Volume		1849.0
Less:		
Cumulative Production	437	
Proved Reserves	266	703.0
		1146.0

Proved reserves of natural gas are compiled and reported by the A.G.A. and are defined as follows:

> "Proved reserves may be both drilled and undrilled. Undrilled reserves are located so close to the drilled reserves that every reasonable probability exists that they will be producible when drilled. Proved reserves are made up of associated and nonassociated gas which simply indicates whether the reserves are to be produced with oil or not."

The quantity of proved natural gas reserves was about 265 trillion CF as of December 31, 1972. Proved reserves and probable potential supplies are considered "assured." Possible potential supplies are "reasonably assured" and speculative supplies are speculative. The geographical location of the potential gas supply is summarized in Figure 3-7 by probable, possible, and speculative categories as of December 31, 1972.

In summary, 68.1% (780 trillion CF) of the potential gas estimated by the Potential Gas Committee is located in the Lower 48 States. The remaining 31.9% (366 trillion CF) is located in Alaska. Approximately 70.5% of the gas from the Lower 48 will be found onshore, with 413 trillion CF in the well depth range of 0-15,000 feet and 137 trillion CF in the depth range of 15,000-30,000 feet. The offshore areas of the Lower 48 account for the remaining 29.5% (230 trillion CF) of the potential supply.

3.1.4 Natural Gas Liquids

Estimates of the quantity of natural gas liquids that are ultimately recoverable have not been made by the NPC. Natural gas liquids are extracted from natural gas as it is produced from the well. The NPC does, however, project the quantity of natural gas liquids production up to 1985. The following fuels are derived from natural gas liquids: condensate, pentane and heavier hydrocarbons, and LPG.

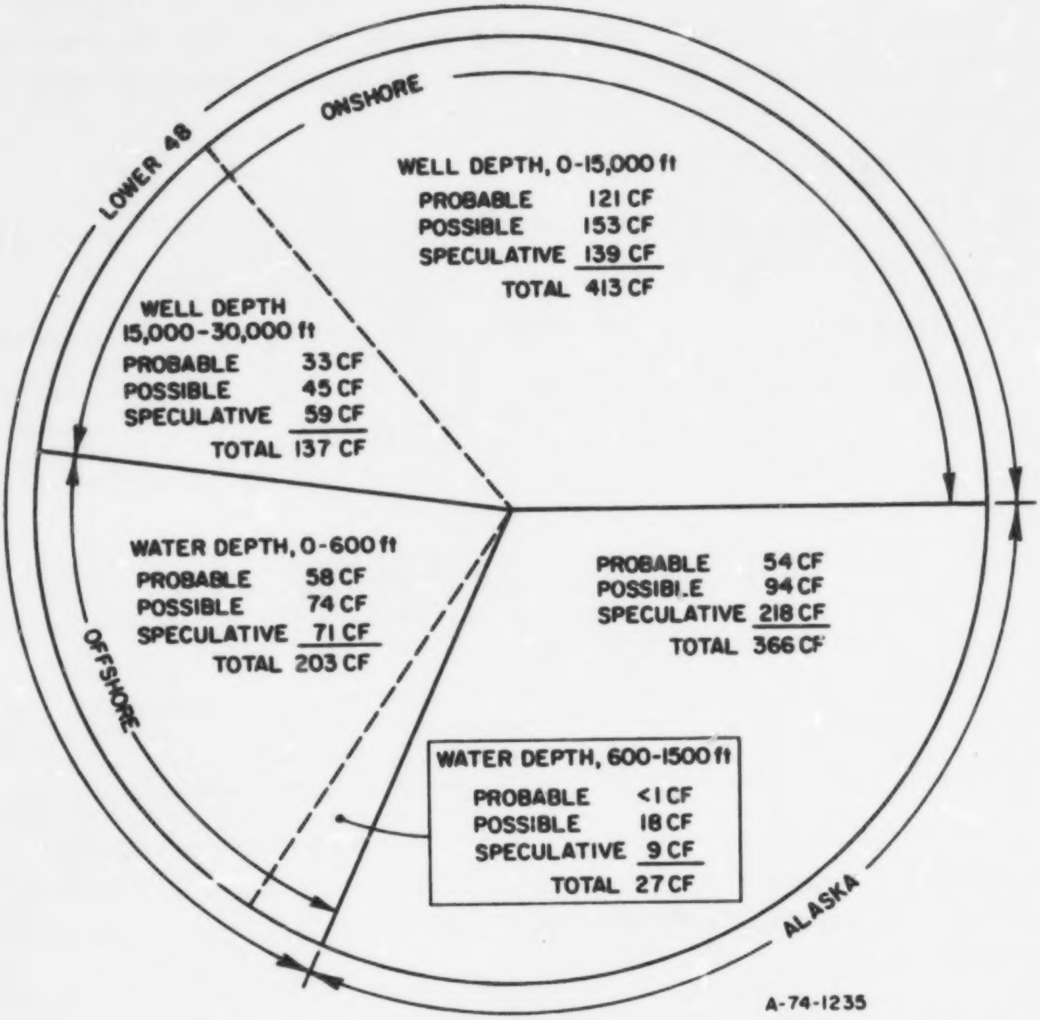

LOWER 48
ONSHORE
WELL DEPTH, 0-15,000 ft
PROBABLE 121 CF
POSSIBLE 153 CF
SPECULATIVE 139 CF
TOTAL 413 CF
WELL DEPTH
15,000-30,000 ft
PROBABLE 33 CF
POSSIBLE 45 CF
SPECULATIVE 59 CF
TOTAL 137 CF
WATER DEPTH, 0-600 ft
PROBABLE 58 CF
POSSIBLE 74 CF
SPECULATIVE 71 CF
TOTAL 203 CF
OFFSHORE
PROBABLE 54 CF
POSSIBLE 94 CF
SPECULATIVE 218 CF
TOTAL 366 CF
WATER DEPTH, 600-1500 ft
PROBABLE <1 CF
POSSIBLE 18 CF
SPECULATIVE 9 CF
TOTAL 27 CF
ALASKA
A-74-1235

Figure 3-7. CATEGORIZATION OF U.S. POTENTIAL GAS SUPPLY

Although the ultimately recoverable quantity of natural gas liquids has not been estimated, the quantity of proved reserves is about 6.8×10^9 bbl, which is assumed to be an "assured" resource. This estimate of reserves is based upon the historical ratio of natural gas to natural gas liquids discoveries. Based on the assumption that no economic or technical limitations will limit future natural gas liquids production, the current reserves-to-production ratio is approximately 9 years based on 1972 production.

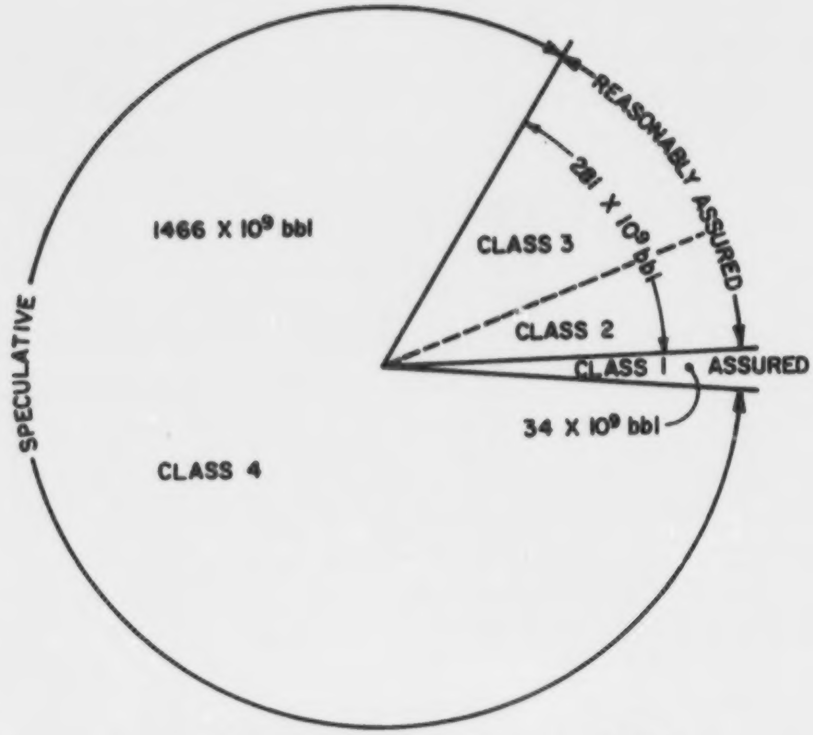
3.1.5 Oil Shale

The NPC[8] estimates domestic oil shale resources at 1781 billion bbl. Resources of oil shale are classified into one of four groups:

1, 2	These are the resources satisfying the basic assumption limiting resources to deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale, by assay. Only the most accessible and better defined deposits are included. Class 1 is a more restrictive cut of these reserves and indicates that portion which would average 35 gallons per ton over a continuous interval of at least 30 feet.
3	Class 3 resources, although matching Classes 1 and 2 in richness, are more poorly defined and not as favorably located. These may be considered potential resources and would be exploitation targets at the exhaustion of Class 1 and Class 2 resources.
4	These are lower grade, poorly defined deposits ranging down to 15 gallons per ton which, although not of current commercial interest, represent a target in the event that their recovery becomes feasible. These may be considered speculative resources.

Class 1 deposits are considered as an "assured" resource base; Class 2 and 3 deposits are "reasonably assured"; and Class 4 formations are "speculative" as a resource base. The appropriate quantities are shown in Figure 3-8.

Of the total resource base, 129 billion bbl are in Classes 1 and 2 and would be equivalent to 54 billion bbl of syncrude oil. The location of major U.S. oil shale deposits is shown in Figure 3-9 and Table 3-7.



A-94-1631

Figure 3-8. CATEGORIZATION OF DOMESTIC SHALE OIL RESERVES

Table 3-7. SUMMARY OF OIL SHALE RESOURCES[1] IN GREEN RIVER FORMATION (Source: Ref. 10)

	Resources				
	Class 1	Class 2	Class 3	Class 4	Total
Location	10^9 bbl				
Piceance Basin Colorado	34	83	167	916	1200
Uinta Basin Colorado and Utah	--	12	15	294	321
Wyoming	--	--	4	256	260
Total	34	95	186	1466	1781

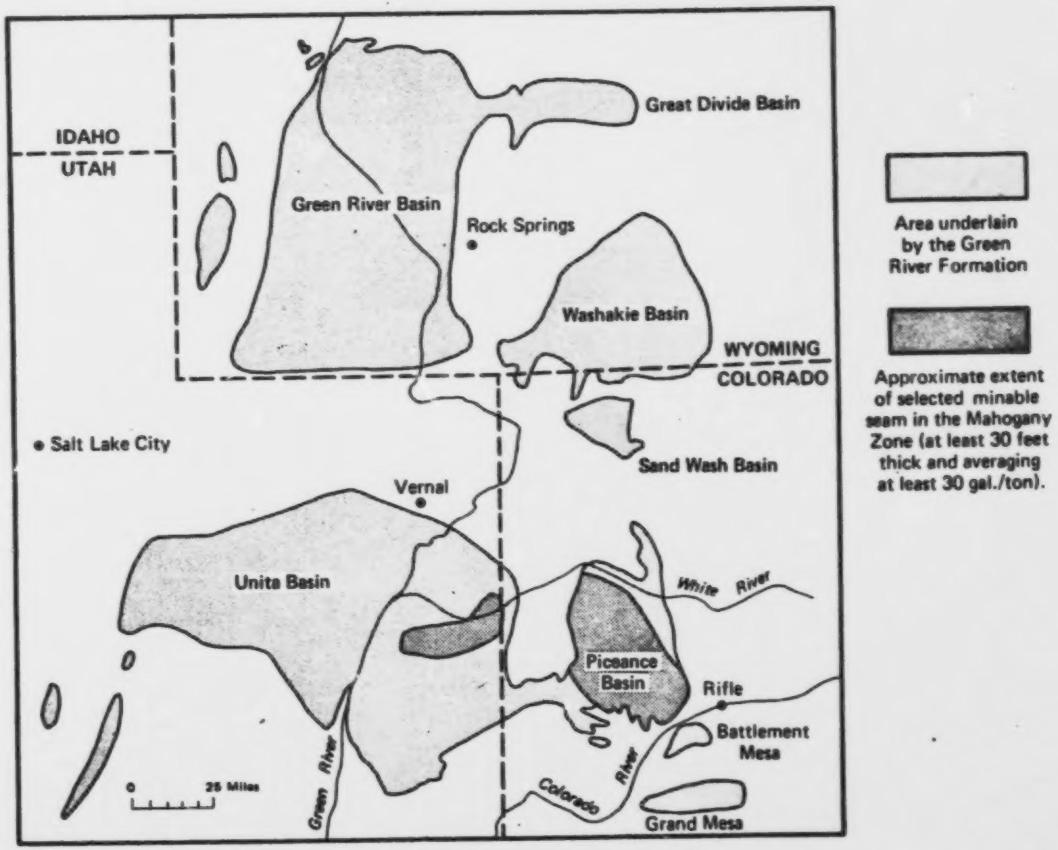

IDAHO
UTAH
Green River Basin
Great Divide Basin
Rock Springs
Washakie Basin
WYOMING
COLORADO
Sand Wash Basin
Salt Lake City
Vernal
Unita Basin
White River
Piceance Basin
Rifle
Battlement Mesa
Grand Mesa
Colorado River
Green River
0 25 Miles
Area underlain by the Green River Formation
Approximate extent of selected minable seam in the Mahogany Zone (at least 30 feet thick and averaging at least 30 gal./ton).

Figure 3-9. LOCATION OF MAJOR OIL SHALE RESOURCES (Source: Ref. 10)*

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Oil shale deposits have been found in other regions of the U.S. These deposits, however, have been assayed at less than 15 gallons of syncrude per ton and are not considered to be of commercial significance until the more readily available resources are depleted. About 80% of the oil shale within Classes 1 and 2 is located on Federal lands. Because of this, development of oil shale resources would involve public as well as private participation in areas of research and development.

3.1.6 Tar Sands

Tar sands is a term used to describe hydrocarbon-bearing deposits to be distinguished from more conventional oil and gas reservoirs. The high viscosity of the hydrocarbon does not permit recovery in its natural state by a conventional well as in the production of crude oil. In-place domestic resources of tar sands are estimated by the NPC[10] to range from 17.7 to 27.6 billion bbl. Efficiency estimates[8] for conversion of tar sands to synthetic crude (salable product) range from 35 to 87%, resulting in a maximum of 23.5 billion bbl of crude oil equivalent, or an amount that is about equal to 6% of the remaining domestic discoverable crude oil. The major resources of tar sands are located in five areas of Utah. They are listed in Table 3-8 and are currently not produced on a commercial basis. Because only small quantities of tar sands lie within the U.S., a major development of this resource is unlikely; however, it can be considered an assured resource.

Table 3-8. ESTIMATED IN-PLACE RESOURCES OF UTAH TAR SANDS DEPOSITS (Source: Ref. 10)

	10^9 bbl
Tar Sand Triangle	10.0-18.1
P.R. Spring	3.7- 4.0
Sunnyside	2.0- 3.0
Circle Cliffs	1.0- 1.3
Asphalt Ridge	1.0- 1.2
Total	17.7-27.6

3.2 Nuclear Energy Resources

3.2.1 Uranium

The NPC estimates[7] of proved and potential uranium resources are based on AEC projections that have been updated to January 1973. The AEC resource levels are presented in terms of cutoff costs of production. Three cost levels are discussed in the NPC report: $8, $10, and $15/lb. Present estimates of proved and potential uranium resources at a cost of up to $15/lb are about 1.5 million tons. Proved reserves at $8/lb are estimated to be 273,000 tons as of January 1, 1973 (Table 3-9). The potential estimates shown are related to specifically known mineralization and geological trends and, as such, are subject to review as new information becomes available.

Table 3-9. DOMESTIC RESOURCES OF URANIUM AS ESTIMATED BY THE AEC, JANUARY 1, 1973 (Source: Ref. 15)

Cost of Production,* $/lb	Proved Reserves	Potential Reserves	Total
	tons U_3O_8		
8 (or less)	273,000	450,000	723,000
10 (or less)	337,000†	700,000	1,033,000
15 (or less)	520,000†	1,000,000	1,520,000

* Based on the forward cost of production, not including amortization of past investments, interest, or income taxes; also, no provision is made for return on investment; does not necessarily represent the market price.

† Includes 90,000 tons potentially recoverable as a by-product of phosphate and copper mining at a cost of $10/lb or less.

Substantially all the proved reserves of uranium (U_3O_8) and approximately 85% of the reserves categorized by the AEC as potential resources are located in the present producing areas; yet these areas constitute less than 10% of the total region where evidence of uranium occurs. In many cases, present producing areas have not been completely explored. Because about 50% of all proved and potential uranium resources are on Federal or Indian lands in the western U.S., reasonable access to these lands must be allowed to support necessary exploration and development efforts. Proved reserves (at $15/lb or less) are considered "assured," and potential reserves are classified as "reasonably assured." These quantities are shown in Figure 3-10.

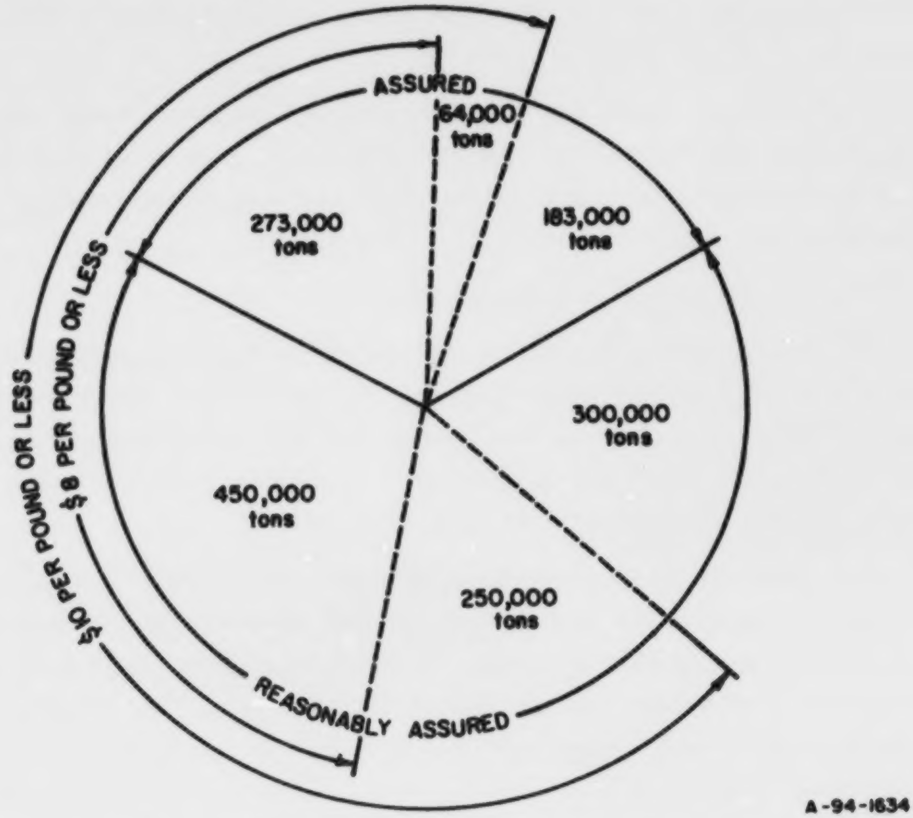

Figure 3-10. DOMESTIC RESERVES OF URANIUM AT $15 PER POUND OR LESS

3.2.2 Thorium

The resource base of thorium in the U.S. is currently estimated at about 295,000 tons. This estimate includes resources that are recoverable as by-products and high- and low-grade non-by-product quantities. The only reserves that are mined currently are Atlantic Coast beach placers, where monazite (the raw material ore) is produced as a minor by-product of titanium mining.

Large resources of relatively high-grade thorium of more than 0.1% are located in Idaho and Montana. A second large potential source is in a low-grade deposit of granite near Conway, N.H.

Assured reserves are about 46,000 tons recovered as a by-product. The remaining reserves, 249,000 tons, are classified as reasonably assured.

Thorium resources are not well-defined because of the relatively small past demand. The amount of thorium recovered as a by-product has been more than sufficient to meet current needs, and as a result, the deposits cannot be mined at a profit.

3.2.3 Nuclear Fusion Reactors

The predictability of controlled thermonuclear (fusion) reactor development, in both pattern and schedule, is very low. We do not expect it to be a significant factor in the overall energy supply picture by 2000, but there is a small probability (perhaps 1%) that it could be a much larger factor than anyone has publicly ventured to predict.

The AEC and those working under its sponsorship are in almost unanimous agreement that fusion reactor commercialization will not occur before the end of this century. U.S. development programs based on magnetic confinement of the fusion plasma are rather firmly geared to this schedule, and apparently only a dramatic crash program, not yet on the horizon, would accelerate it noticeably. Such a program would be politically feasible if, for example, Russian or other foreign technological efforts begin to show near-term commercial possibilities, but it is still too soon to predict such occurrences. Such a program also would become a real possibility if the energy shortage were to become much worse, but the formidability of the problems of magnetic confinement of fusion make it more likely that other domestic developments, such as coal gasification and liquefaction programs, would be given even higher priorities in efforts to meet pre-2000 energy supply crises.

The largest uncertainty is the rate at which laser fusion development will proceed. Most authoritative sources predict that this technology will develop even more slowly than magnetic confinement technology, pointing out that even technical feasibility is still questionable. Historically, new energy forms are developed to commercial significance over a few decades rather than over a few years. Optimistic representations of development prospects can be expected from both political figures and scientists/technologists. This optimism must be considered in the light of the lead time required for commercial development. Laser fusion possibilities are receiving intense worldwide attention, mostly unpublicized for military as well as for commercial reasons. The scientific possibilities are many and largely unevaluated. This immature technology seems to us to be quite capable of making rapid, unpredictable advances that could attain commercial significance after 2000. Nobody, to our knowledge, has information from which he can predict with any confidence that there is a certain probability of this happening, but the possibility must be acknowledged.

3.3 Renewable Resources

3.3.1 Hydropower

Hydropower is conventionally used in the generation of electricity. The total hydroelectric energy potential of the U.S. (exclusive of Alaska) as of January 1, 1971, is estimated to be about 530 billion kWhr annually. Of this total, 249 billion kWhr were being generated annually through facilities already installed. The remaining 281 billion kWhr represent the total undeveloped hydroelectric energy in the U.S. Both the developed and undeveloped power are considered assured. However, according to the FPC, economics and other factors may prevent the development of much of this potential. The remaining sites suitable for economic development are limited.

3.3.2 Geothermal Heat

Case I of the NPC study assumes that large geographical areas will be made available for prospecting, including recently opened Federal lands, to encourage exploration and development of geothermal energy in the next 4-5 years. The U.S. resource base is summarized in Table 3-10.

Table 3-10. IN SITU HEAT RESOURCES

Geothermal Resources	Reserve Target for 1985	Resource Base
	10^{15} Btu	
Localized Hydrothermal Systems, Down to 2 Miles Deep	5.6	560
Localized Hydrothermal Systems, Down to 6 Miles Deep	2.8	2800

The localized geothermal systems less than 2 miles down are considered assured, and those between 2 and 6 miles down are reasonably assured. The most favorable areas of geothermal production in the U.S. are in the western part of the country, primarily in the states of California, Nevada, Oregon, Washington, Idaho, Utah, Arizona, Wyoming, Montana, Colorado, and New Mexico. Alaska and Hawaii also can be included with this group. This is evidenced by high heat gradients and the occurrence of large numbers of warm to hot springs, fumaroles, and geyser complexes whose temperatures approach the local boiling point.

Some of these localities are represented by a single spring of low flow and enthalpy, whereas others, such as Yellowstone National Park, Wyo., cover many acres. About 100 of these hot-fluid-surface localities are close to the boiling point.

The Western U.S. also contains much surface evidence of recent (Quaternary) volcanism. Many hot springs are associated with recent faulting. Much of it is basin and range type, in areas of recent volcanism. Other springs are located in areas where the earth's crust is believed to be thin and where convective rifting has taken place. In both cases, faults serve as the vehicle for heat flow to the surface.

3.3.3 Solar Energy

Solar energy is undoubtedly the earth's most underutilized resource of energy. However, it is so diffusely distributed and so variable in intensity that the capital costs of its collection and application have commonly precluded its more general use. Until recent years, when the energy affluence of many countries began to decline noticeably, very little money and effort were devoted to the development of even the well-recognized possibilities for solar energy exploitation.

For the "average day" in a year, the solar energy received by a horizontal surface at ground level in the U.S. is about 1400 Btu/sq ft. This corresponds to about 58 Btu/sq ft-hr (24-hour day), or about 17 watts/sq ft over 24 hours. The "assured" energy is then about 14.4×10^{15} kWhr/yr. This is much less than the intensity of radiant energy projected toward the earth from the sun. This solar constant is about 10,330 Btu/sq ft-day. All the energy consumed in the U.S. in 1970 could have been collected from the sun by a single collector only 27 miles in diameter (570 square miles in area), providing that collector was a satellite above the earth's atmosphere and so situated that it was exposed normal to the sun's rays all the time.

Many ways for converting solar energy to electricity are under development, such as solar thermal conversion, photovoltaic conversion, ocean thermal difference, wind power, and bioconversion. Chemical-fuel-synthesis routes are discussed in other sections.

A solar energy resource assessment usually considers the land areas available or required for energy collection. A form of solar energy capture and energy conversion that is very dependent on land is agriculture or the "solar plantation."

The energy from a plantation is a perpetually renewable source of fuel. Fuel can be produced from plants in several ways. One way is to ferment it to produce alcohol. Another way is to burn it to produce steam and ultimately electricity. A third technique is pyrolysis to produce fuel gases.

If crops are grown as a source of fuel, the land requirements depend on the type of crop and fuel synthesis as well as on the growing conditions. In Section 5, "Fuel Synthesis Technology," Table 5-10 presents examples of crop yields, fuel values, and solar energy conversion efficiencies. For example, on the basis of 5 tons/yr/acre yield and 6500 Btu/lb fuel value, the land requirements for an energy plantation to support a 1000-MW (50% load factor) power plant can be derived as follows. Assuming 10,000 Btu/kWhr, 5 billion Btu/hr is required for a stated power plant. The amount of heat generated per square mile per hr by burning produced fuel will be 475 million Btu (5 X 2000 X 6500 X 640/365 X 24). Therefore, 1053 square miles is required to support the stated power plant. The efficiency of solar energy conversion in this case is about 0.3% on the basis of 54.2 Btu/hr/sq ft of solar energy input. However, the solar energy conversion depends on the type of trees, farm crops, and many other factors. Therefore, the land requirement for a particular amount of fuel production varies considerably from one case to another.

3.3.4 Tidal Energy

The use of the energy in tides to generate power goes back at least to the 11th century when small tidal mills were used to grind corn in several European countries. In 1734, at Slades Mills in Chelsea, Mass., a tidal installation developing 50 hp was used for grinding spices. On Passamaquoddy Bay in Maine, tidal mills were in operation prior to 1800.

A fundamental problem with tides is that the range (distance between high and low water levels) varies widely along the U.S. coast. From Eastport, Me., the tidal range decreases from about 18 to 9 feet at the north shore of Cape Cod. South of Cape Cod, the tidal range is only 4 feet, and this diminishes to about 2 feet off the coast of Florida. A notable exception to the East Coast trend is the approximate 7-foot tidal range in Long Island Sound. On the Gulf Coast, the range is less than 2 feet. For the West Coast, the tidal range increases from about 4 feet at San Diego to about 11 feet at Seattle. Along the Canadian Coast the range is about 12 feet, whereas the Cook Inlet in Alaska experiences about an 18-foot variance. Thus, except for specific bays in Maine and Alaska, the tidal range is too low to be practically useful.

On a yearly average, the tidal range at the head of the Bay of Fundy (Southeast Canada) is about 35 feet. This range is significantly higher than elsewhere on the North American continent and has thus attracted most attention as a potential source of tidal power. In the U.S., Passamaquoddy Bay, with a range of 18-24 feet, also has received much attention.

Many engineering problems would be involved in developing tidal power, even in a relatively favorable area such as the Bay of Fundy. Small-scale development in the Cape Tenny and Cape Maringouin areas would encounter water depths of no more than 60 feet. Water depths near St. John would be up to 250 feet. At the mouth of the bay near Yarmouth, Nova Scotia, and Jonesport, Me., water depths would be about 600 feet. Thus, plans to tap the ultimate potential of the Bay of Fundy and the Passamaquoddy area would have to cope with the larger scale problems of deeper water and the confinement of larger areas of the bay. However, engineering feasibility exists, given the necessary amount of capital.

Similar problems with water depth would occur near Alaska. Although interior portions of the Cook Inlet are no more than 120 feet deep, the mouth of the inlet has depths of 300 feet. The remoteness of the area and the presence of drift ice and silt, together with the possibility of earthquakes, make it unlikely that Alaskan tidal power will be developed in the next 30 years.

If engineering and commercial practicalities are considered and if 15 feet is assumed to be the lowest tidal variance that might be developed in the next 30 years, only the Passamaquoddy Bay region in Maine can qualify. Because this bay is bounded by Canada and Maine, development would necessarily be a joint venture. Actually, Passamaquoddy is a small bay that is a part of the larger Bay of Fundy. The amount of energy that would be potentially available from the U.S. portion of

Passamaquoddy Bay is 1.8 billion kWhr/yr, but this energy can only be classified as "reasonably assured."

3.3.5 Wind Power

From the 1920's until about 1951, considerable research went into estimating the amount of energy available from the wind. These studies concentrated on determining how much wind power is available over the world's land masses and found that there is far more wind over the oceans, which at that time was considered to be untappable.

In 1972, Professor William Heronemus[6] of the University of Massachusetts realized that extensive meteorological data were available from the "Texas Towers," which were erected off the Atlantic Coast during World War II. By using data and experience from prototype windmill generators that had been operating in the 1950's and 1960's in the U.S. and in Great Britain, Heronemus designed a floating-wind-generator concept, and he estimated the size, weight, and cost of several configurations of such units.

Using the Texas Towers' wind-speed information, Heronemus observed the number of hours in the year when the wind would blow at moderate and peak generating conditions. He determined that the wind speed would fall below 15 mph, the minimum generating condition, for about one-third of the year, so a large energy storage system would be required to allow the system to continue generating on a year-round basis. He selected electrolytic hydrogen as his energy "storage battery" concept. Each floating wind generator would house three 2000-kW generators, and 165 of these generators would be clustered around each electrolyzer station, which would correspond to a size already determined in studies conducted by Allis-Chalmers Corp. in 1966. The electrolyzers themselves would be housed in floating reinforced concrete hulls and would be joined together in long chains by an underwater seabed pipeline system.

The total installed plant would have the same generating capacity as the proposed nuclear, fossil-fuel, and hydroelectric pumped storage plant that [illegible] planned for installation in New England between 1976 and 1990. The output of the total plant is to be approximately 160 billion kWhr/yr. Assuming 10 such plants could be built, the assessed resource base would be 5.4 X 10^{15} Btu/yr. To achieve this output, 83 electrolyzer stations, each with its own cluster of wind generators, are required.

A recent article[7] in Environment discusses Heronemus's work and the classic windmill design work that preceded it. Significantly, the article begins by painting a picture of the "Great Plains of Mid-America, from Texas to North Dakota, with a forest of giant windmills, each the height of a 70-story building." Whether such an array of towers would be acceptable to those interested in the beautification of America is one question — a particularly serious one considering intensified public pressure to put unsightly electrical transmission lines underground.

Environmentalists are already challenging the unsightliness of land-based windmills, and at this stage, apparently, widespread use of wind power in the U.S. will be highly unacceptable. The offshore wind power system proposed by Heronemus, however, appears to be more attractive and will undoubtedly receive further attention as an energy source in the future.

3.3.6 Waste Materials

We have assessed the potentials of waste materials as an energy resource, and the practical, large-scale resources are municipal wastes (solids) and animal feedlot wastes (manure). These waste materials could be burned directly to yield thermal energy, or they could be converted to a hydrocarbon fuel like methane. The following discussion gives some estimates of quantities, heating values, and fuel equivalents (as SNG).

3.3.6.1 Municipal Wastes

In 1973, the solid waste collected in the U.S. averaged about 5 lb/person. This total comprises all types of solid wastes, such as household, commercial, industrial, construction, demolition, street and alley, and miscellaneous collections. The per-capita waste production in the U.S. has been rising; it is projected[11] to reach 8 lb by 1990 and almost 10 lb by 2000. Its heating value also is expected to rise because of an increased paper and plastic content of refuse. On the basis of Series E population projection,[17] we have calculated the total heating value of collected refuse in the U.S. from 1970 to 2000 (Table 3-11).

Table 3-11. ESTIMATE OF TOTAL ENERGY AVAILABLE IN MUNICIPAL WASTES, 1970-2000

Year	Population, 10^6 people[*]	Per-Capita Daily Refuse Collected, lb/day[†]	Total Annual Refuse, 10^9 lb/yr	Estimated Heating Value, Btu/lb[†]	Total Heating Value, 10^{12} Btu/yr
1970	204.9	4.5	336	4493	1512
1975	213.9	5.4	422	4582	1932
1980	224.1	6.3	515	4627	2384
1985	235.7	7.0	602	4738[‡]	2853
1990	246.6	8.0	720	4849	3492
1995	256.0	9.0	841	5005[‡]	4209
2000	264.4	9.75	941	5161	4856

[*] Source: Ref. 17.

[†] Source: Ref. 11.

[‡] Estimated.

Assuming that an overall conversion efficiency of 42% can be obtained for converting waste to SNG, the net heating value produced from this municipal waste will increase from 635 trillion Btu in 1970 to 2040 trillion Btu in 2000 (Table 3-12). This resource is considered "assured."

Table 3-12. ESTIMATED SNG GENERATED FROM COLLECTED MUNICIPAL WASTES, 1970-2000

	Total Heating Value	SNG Heating Value[*]
Year	10^{12} Btu/yr	
1970	1512	635
1975	1932	811
1980	2384	1001
1985	2853	1198
1990	3492	1467
1995	4209	1768
2000	4856	2040

[*] Assumes that overall thermal efficiency of conversion is 42% (Source: Ref. 5).

3.3.6.2 Animal Feedlot Wastes

Animal feedlots constitute the largest single source of waste products. Cattle represent the largest single category for the production of wastes in feedlots. According to a consensus of statistics of solid animal wastes only, cattle account for almost 90% of the total.

By using statistics from Statistical Abstract,[16] a ratio of the animals slaughtered to the total population can be calculated (Table 3-13). These ratios decrease from 4.2 in 1950 to 3.0 in 1973. We cannot determine whether this trend will continue or reverse, so we have assumed that it will level off at 3.0. For our purpose, this is a conservative number, and it is doubtful that the ratio will reverse itself and begin to increase because the cost of keeping animals will not decrease. As a result, the feedlot owner will try to keep the ratio of cattle population to the slaughter as low as possible.

Table 3-13. DATA ON POPULATION AND NUMBER OF CATTLE SLAUGHTERED, 1950-1973 (Source: Refs. 3 and 16)

Year	Total Population (million head)	Number Slaughtered (million head)	Ratio, population/slaughtered
1950	78	18.6	4.19
1956	97	26.6	3.65
1960	96	26.0	3.69
1965	109	33.2	3.28
1970	112	35.4	3.16
1971	115	35.9	3.20
1972	118	38.8	3.04
1973	122	41.1	2.97

On this basis, the total cattle population is estimated to be 153 million head in 1980 and 177 million head in 1985. This is compared with a total of 118 million head in 1972. Extrapolating these data in a straight line to 2000 results in a total population of 245 million head of cattle (Table 3-14).

Table 3-14. ESTIMATE OF TOTAL CATTLE POPULATION, 1970-2000

Year	Population, 10^6 head
1970	112*
1971	115*
1972	118*
1973	122*
1975	130†
1980	153†
1985	177†
1990	197†
1995	221†
2000	245†

* Source: Ref. 16.

† Calculated.

The average daily wet manure production of cattle is 60-80 lb/head. The lower value is usually given for beef cattle and the upper for dairy cattle. We have used an average of 70 lb/day of wet manure. This would mean that, by 2000, the total production of wet manure would be 3130 million tons (Table 3-15), compared with 1400 million tons in 1972.

Table 3-15. ESTIMATED MANURE PRODUCTION, 1975-2000

	Manure	
	Wet Basis	Dry Basis
Year	10^6 tons	
1975	1600	332
1980	1955	391
1985	2260	452
1990	2555	511
1995	2860	572
2000	3130	626

To convert this to an equivalent total SNG heating value, we assumed that manure has a heating value of 7500 Btu/lb (dry) and that manure is 80% liquid. Table 3-25 shows an estimate of the production of manure on a dry basis as 20% of the production on a wet basis. Thus, the potential production of SNG from manure is 4980 trillion Btu in 1975 and 9390 trillion Btu in 2000; however, these are gross numbers. Realistically, a 50% conversion of the gross Btu content to SNG is possible, so the production of SNG from manure could be almost 2500 trillion Btu in 1975 and 4700 trillion in 2000 (Table 3-16). For this study, all animal feedlot wastes are considered an "assured" resource.

Table 3-16. ESTIMATED POTENTIAL PRODUCTION OF SNG FROM MANURE, 1975-2000

Year	Total Heating Value	SNG Production
	10^{12} Btu/yr	
1975	4980	2490
1980	5866	2933
1985	6780	3390
1990	7666	3833
1995	8580	4290
2000	9390	4695

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4. ENERGY DEMAND AND SUPPLY MODELS

The competing demand for energy and fuels in the future has been assessed through the formulation of two energy models. Model I is based, in part, on the NPC study.[4] Model II is based, in part, on a special report for the Gas Supply Committee of the A.G.A. prepared by Dr. Henry R. Linden of IGT.[2] Both of these studies project the energy supply incrementally to the year 2000.

Model I shows that U.S. energy self-sufficiency is theoretically feasible during the mid-term time frame (1985-2000). Model II assumes that energy demand increases at an annual rate greater than that in Model I and that the U.S. will not become self-sufficient during the time frames of this study. In the case of both models, deficits would be filled by imports.

These models are not intended for the purpose of energy allocation in the future; rather, they are quantitative indications of energy supply and demand deficits and/or excesses. A true "modeling situation" requires a more extensive establishment and definition of parameters, which are beyond the scope of this study. One objective of this study is the determination of the need for and the quantities of an alternative fuel in some future time frame. Our methodology for selecting energy sources and alternative fuels uses the projections of the economic models.

4.1 Model I

As previously stated, Model I contains data from the NPC report.[4] The NPC projected three levels of energy demand: high, medium, and low in 5-year increments up to 1985 followed by a 15-year interval to 2000. We selected the low level of projected energy demand for our model. For the period 2000-2020, energy demand is assumed to continue to grow at the same annual rate as in 1985-2000, 2.8%. This assumption was made because the NPC did not go beyond 2000.

Future energy supplies also are based on NPC data. Unlike energy demand projections, the energy supply projections were presented in a series of four cases. Each supply case is based on a different set of parameters related to resource finding and production rates. Case I represents the highest quantity of domestic energy supply, whereas Case IV represents the lowest quantity. Case I was selected for our model.

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The NPC report is a widely used and the most up-to-date energy resource analysis available. We selected it for use here to avoid generating yet another assessment of energy resources and demands. The assumptions upon which the Case I energy supply quantities are based closely approximate an optimistic situation in which a maximum effort is undertaken to make the U. S. energy supply self-sufficient at the earliest possible date. These conditions best fit the ground rules of this study, i. e., to assess the feasibility of alternative automotive fuels based on U. S. domestic resources.

Four variables were selected by the NPC as being most significant in determining the level of energy demand. These variables are economic activity (GNP), cost of energy, population growth, and environmental constraint. Under Model I, the future economic growth rate (GNP) is assumed to be 3.2% annually up to 1985, in terms of real economic increase. Industrial production and real personal income are assumed to vary in proportion to the changes occurring in GNP. All demographic factors are included under the single variable – population. Model I population growth is expected to increase at an annual rate of 1%.

As justification for Model I demand levels, an immediate reduction in the rate of increase of energy consumption would be attributed to increased prices that, in turn, induce more efficient energy utilization. Efficiency improvements are brought about by improved design of heating and cooling equipment for residential, commercial, and industrial applications; greater use of building insulation materials; and lighter weight vehicles.

Some moderate changes in domestic petroleum and synthetic fuel supply have been incorporated, and they are contained in Table 4-1. Most of these changes concern shale oil production, coal liquefaction, and SNG production, and they reflect recent projections for development of these industries.[3] These projections serve as optimistic updates to certain portions of NPC Case I, and they are in the spirit of U. S. energy independence. They do not significantly change the overall energy supply according to NPC Case I, and they have no effect on the NPC level of energy demand.

Some important assumptions had to be made for Model I to arrive at an energy supply and demand projection arranged according to market segment. The NPC report provided only gross energy demand numbers for each consuming segment. No attempt was made in the NPC study to show how the demand was to be satisfied, i.e., the quantity of each energy resource that is likely to be consumed within each of the market segments. Table 4-1 summarizes energy demand and the quantity of each domestic source supplied.

Table 4-1. MODEL I ENERGY SUPPLY AND DEMAND BY MARKET SECTORS

	1970	1975	1980	1985	2000*	2020*
	10^{15} Btu					
Demand						
Residential/Commercial	15.8	18.2	21.1	23.9	36.2	62.8
Industrial	20.0	22.2	24.7	27.1	41.0	71.2
Transportation	16.3	19.4	23.0	26.7	40.4	70.2
Electricity Conversion	11.6	15.5	20.7	26.7	40.4	70.2
Nonenergy	4.1	5.0	6.2	8.1	12.3	21.3
Total	67.8	80.3	95.7	112.5	170.3	295.7
Supply						
Oil						
Conventional (Wellhead)	21.0	23.7	27.3	31.7	31.0	31.0
Oil Shale	0	0	0.6	1.9	6.7	6.7
Coal Liquefaction	0	0	0.2	1.1	10.2	13.0
Total	21.0	23.7	28.1	34.7	47.9	50.7
Gas Production						
Conventional (Well)	22.4	24.5	24.6	28.0	22.0	15.0
SNG From Coal	0	0	1.0	2.0	8.0	10.0
Total	22.4	24.5	25.6	30.0	30.0	25.0
Coal (Traditional Uses)	13.1	16.6	21.1	27.1	35.0	64.0
Hydro and Geothermal	2.7	3.1	4.0	4.7	5.0	5.0
Nuclear (Heat)	0.2	4.0	11.3	29.8	102.0	275.0
Total	59.4	71.9	90.3	126.3	219.9	419.7

* The assumed rate of growth for 2000-2020 is 2.8% /yr, which is the same for the 1985-2000 period except for nuclear power supply figures.

To determine the areas of potential energy oversupply or shortfall, the following assumptions were made:

- All market segments consume approximately the same percentage share of total energy as they now do. In 1975, this is expected to be as follows: residential and commercial, 22.7% ; industrial, 27.6% ; transportation, 24.2% ; electricity conversion, 19.3% ; other, 6.2% . By 1985, these percentages will change slightly: residential and commercial, 21.2% ; industrial, 24.1%; transportation, 23.7%; electricity conversion, 23.7% ; other, 72. % . For the years 2000 and 2020, the market segments are assumed to consume these same percentages.

- The residential and commercial market segment receives top priority in terms of fulfilling its needs from domestic supply sources. The categories of industrial and other are next in priority. The electricity generation segment supplies energy for the priority markets, and excess power (after filling deficits) is available to the transportation sector.

- The utilization of coal in residential and commercial applications becomes negligible by 1980. Essentially the coal is used in electricity generation, chemical fuel synthesis, and industrial processes.

- The utilization of oil for electricity generation continues to increase up to 1975 and remains at that level. The rate of growth up to 1975 is based on historical 1961-70 data.

- Electrical generation does not consume more natural gas than in 1970.

- All nuclear fuels are used for electricity generation. The efficiency of this conversion is assumed to be 35% in all time periods.

These assumptions result in the energy supply and demand apportionments in Table 4-2 through 4-6. These predictions are not purported to be accurate, especially beyond 1985, and they are not recommended as allocation schedules. They constitute a self-consistent model for energy accounting, and they result in the quantities of energy available for transportation shown in Table 4-7. Except for the effect of the energy conversion efficiency (35%) in the 1985-2020 time period, moderate changes in these assumptions have only small effects on the quantities shown in Table 4-7. If the energy conversion efficiency is changed (increased) moderately, significant changes (improvements) occur in energy availability for transportation (Table 4-7). An example of this effect is presented in Section 11.3.

Table 4-2. MODEL I RESIDENTIAL AND COMMERCIAL ENERGY SUPPLY AND DEMAND

	1970	1975	1980	1985	2000	2020
	10^{15} Btu					
Demand	15.8	18.2	21.1	23.9	36.2	62.8
Supply						
Oil (21% of Supply)	4.4	5.0	5.9	7.3	10.1	10.6
Gas (31.3% of Supply)	7.0	7.6	8.0	9.3	9.3	7.8
Coal (2.3% of Supply)	0.3	0.3	0	0	0	0
Total (Excluding Electricity)	11.7	12.9	13.9	16.6	19.4	18.4
Electricity Consumption*	2.6	3.0	3.5	3.9	6.0	10.3
Total Supply	14.3	15.9	17.4	20.5	25.6	28.7
Deficit in Domestic Supply	1.5	2.3	3.2	3.4	10.6	34.1

* Electricity consumption at a constant percentage of the total energy consumption in 1970 (16.5%).

Table 4-3. MODEL I INDUSTRIAL ENERGY SUPPLY AND DEMAND

	1970	1975	1980	1985	2000	2020
	10^{15} Btu					
Demand	20.0	22.2	24.7	27.1	41.0	71.2
Supply						
Oil (17.5% of Supply)	3.7	4.1	4.9	6.1	8.4	8.9
Gas (35.5% of Supply)	7.9	8.7	9.1	10.7	10.7	8.9
Coal (35.7% of Supply)	4.7	5.9	7.6	9.7	12.5	22.8
Total (Excluding Electricity)	16.3	18.7	21.6	26.5	31.6	40.6
Electricity Consumption	2.0	2.2	2.5	2.7	4.1	7.1
Total Supply	18.3	20.9	24.1	29.2	35.7	47.7
Deficit in Domestic Supply	1.7	1.3	0.6	(2.1)	5.3	23.5

* Electricity consumption at a constant percentage of the total energy consumed in 1970 (10%).

Table 4-4. MODEL I ELECTRICITY CONVERSION SUPPLY AND DEMAND

	1970	1975	1980	1985	2000	2020
	10^{15} Btu					
Demand (Heat)	16.2	17.5	20.7	23.0	35.0	60.0
Supply						
Oil (6.1% of Supply)	1.3	1.4	1.4	1.4	1.4	1.4
Gas (17.5% of Supply)	3.9	3.9	3.9	3.9	3.9	3.9
Coal (62.0% of Supply)	8.1	10.3	13.1	16.8	21.7	39.7
Hydro and Geothermal (100% of Supply)	2.7	3.1	4.0	4.7	5.0	5.0
Nuclear (Heat)	0.2	4.0	11.0	29.8	102.0	275.0
Total	16.2	22.7	33.7	56.6	134.0	325.0
Electricity Produced Based on Available Energy Supply	4.9	7.9	11.8	19.8	46.9	113.8
Electricity Required to Satisfy Demands (Except Transportation)	4.9	5.3	6.2	6.8	10.5	17.9
Electricity Potentially Available	0.0	2.6	5.6	13.0	36.4	95.9

Table 4-5. MODEL I TRANSPORTATION ENERGY SUPPLY AND DEMAND

	1970	1975	1980	1985	2000	2020
	10^{15} Btu					
Demand	16.3	19.4	23.0	26.7	40.4	70.1
Supply						
Oil (54.7% of Supply)	11.5	13.0	15.4	19.0	26.2	27.7
Gas (0.0% of Supply)	0	0	0	0	0	0
Coal (0.1% of Supply)	Negl	Negl	Negl	Negl	Negl	Negl
Total (Excluding Electricity)	11.5	13.0	15.4	19.0	26.2	27.7
Electricity Consumption	Negl	Negl	0.2	0.3	0.4	0.7
Total Supply	11.5	13.0	15.6	19.3	26.6	28.4
Deficit in Domestic Supply	4.8	6.4	7.4	7.4	13.8	41.7

Table 4-6. MODEL I OTHER USES SUPPLY AND DEMAND

	1970	1975	1980	1985	2000	2020
	10^{15} Btu					
Demand	4.1	5.0	6.2	8.1	12.3	21.3
Supply						
Oil (0.6% of Supply)	0.1	0.1	0.2	0.2	0.3	0.3
Gas (15.8% of Supply)	3.5	3.9	4.0	4.7	4.7	4.0
Coal (0% of Supply)	0	0	0	0	0	0
Total (Excluding Electricity)	3.6	4.0	4.2	4.9	5.0	4.3
Electricity Consumption*	0.1	0.1	0.1	0.2	0.3	0.5
Total Supply	3.7	4.1	4.3	5.1	5.3	4.8
Deficit in Domestic Supply	0.4	0.9	1.9	3.0	7.0	16.5

* Expressed as a constant percentage of the total energy consumed in 1970 (2.5%).

The NPC Case I supply conditions include the importation of oil and natural gas necessary to satisfy any shortfall between domestic energy supply and demand up to 1985. By 1985 and afterward, a potential domestic surplus exists in the quantity of thermal energy available in the form of coal and nuclear energy. According to Model I, most of this surplus is nuclear energy. This surplus, which is converted to electricity, could be exploited to satisfy shortfalls in the transportation segment. The electricity could be used for converting other materials to a compatible automobile fuel, e.g., the electrolysis of water to obtain hydrogen for use in other fuel conversion systems. Alternatively, and perhaps more efficiently, the nuclear heat could be used directly for chemical fuel synthesis.

The electricity sector, Table 4-4, will be unable to consume all the coal and nuclear energy potentially available to it in the near term. Currently, there is not enough coal-burning equipment installed that is capable of handling the projected quantities of coal. In Model I, this excess energy supply is mathematically converted to electricity (or to a chemical fuel) at 35% overall efficiency, and it is assigned to fill any deficits in the consuming market segments according to the priorities outlined above. After deficits in markets other than transportation have been fulfilled, the transportation market would be assigned more energy to alleviate its shortfalls.

Note that the transportation energy demand is tabulated in units of heat energy or fuel heating value input to the vehicle. Other sector demands are a mix of primarily heat energy with some electricity requirements. Electric vehicles are excluded from this study, but the transportation energy demand would be less in terms of the electricity input to electric vehicles.

The quantity of energy available to the transportation segment, in the form of electricity or synthetic fuel, is shown in Table 4-7. As shown, the potential electricity (or synthesized fuel) will be available for the transportation sector by 1985. However, if the transportation energy demand continues its growth as projected by this model, even the optimistic quantities of coal- and nuclear-based electricity or fuel will in insufficient before the year 2000.

Table 4-7. ENERGY AVAILABLE FOR TRANSPORTATION IN MODEL I

	1975	1980	1985	2000	2020
			10^{15} Btu		
Transportation Shortfall	6.4	7.4	7.4	13.8	41.7
All Other (Priority) Shortfalls	4.5	5.7	4.3	22.9	74.1
Electricity or Synthetic Fuel Potentially Available	2.6	5.6	13.0	36.4	95.9
Electricity or Synthetic Fuel Available for Transportation	Nil	Nil	8.7	13.5	21.8

In summary, Model I assumes not only optimistic oil and gas supplies until beyond 2000, but also a large increase in coal output (about 250% from 1975 to 2000) and a huge increase in nuclear energy (about 2500% from 1975 to 2000). Just as important, the overall energy demand in Model I grows at a "slow" rate, 3.4% for 1970-85 and 2.8% for 1985-2000 (215% overall from 1975 to 2000).

Beyond 2000, the energy demand continues to increase at 2.8% per year. In essence, under the conditions set forth for Model I, the U.S. could become energy independent by 1985. However, we would not stay that way. By the far-term time period (beyond 2000), we would not be self-sufficient in transportation energy unless a more efficient process for converting heat to electricity or a chemical fuel is developed.

4.2 Model II

The Model II energy demand and supply projection is less optimistic than that in Model I, and the Model II demand level is much higher because of electricity generation requirements. Model II supply quantities of energy are in closer agreement with NPC Cases II and III. Unlike Model I supply and demand projections, those in Model II do not show any indication of crossing or a condition of future "energy surpluses." Figure 4-1 compares the overall supply and demand estimates of Models I and II.

An important assumption in Model II, not considered in Model I, is that the ratio of energy consumption per dollar of GNP does not remain stable but continually increases with the passage of time. This is attributed mainly to an increase in the degree of electrification, with associated efficiency losses and waste heat, and also to the production of synthetic fuels from petroleum, oil shale, and coal. These processes will involve further energy losses that, in turn, will decrease the overall efficiency of energy utilization. This is expected to occur in spite of continuing conservation efforts.

The NPC has recognized that, from 1967 through 1970, the use of energy increased more rapdily than the GNP. However, in the level of energy used in Model I, this trend is expected to be reversed by greater utilization efficiencies brought about by acceleration in technology. Energy used for environmental protection or improvement also is taken into consideration in Model II.

We have determined the incremental energy demand required by the anticipated increase in electrification and have otherwise apportioned the energy demands according to the previously listed assumptions (for Model I). The results are shown in Table 4-8 and Figure 4-2.

In contrast to Model I, no potential energy surpluses exist in any time period; in fact, all sectors require sizable imports of oil and gas if demand projections are to be met. According to the assumptions of the model, including that of a high energy demand from increased electrification and fuel synthesis, the energy demand and supply has been projected for the various consuming sectors: residential and commercial, high priority; industrial, moderate priority; other, moderate priority; and transportation, low priority. A separate composite listing of the fuels used to generate electricity has also been made; refer to Tables 4-9 through 4-13.

Model II, like Model I, is not intended for use as a schedule for energy allocation. The mismatches between supply and demand for energy are the result of the assumptions and priorities made to establish the model; however, the fuel deficits are quantitative, which is the objective of the model. The

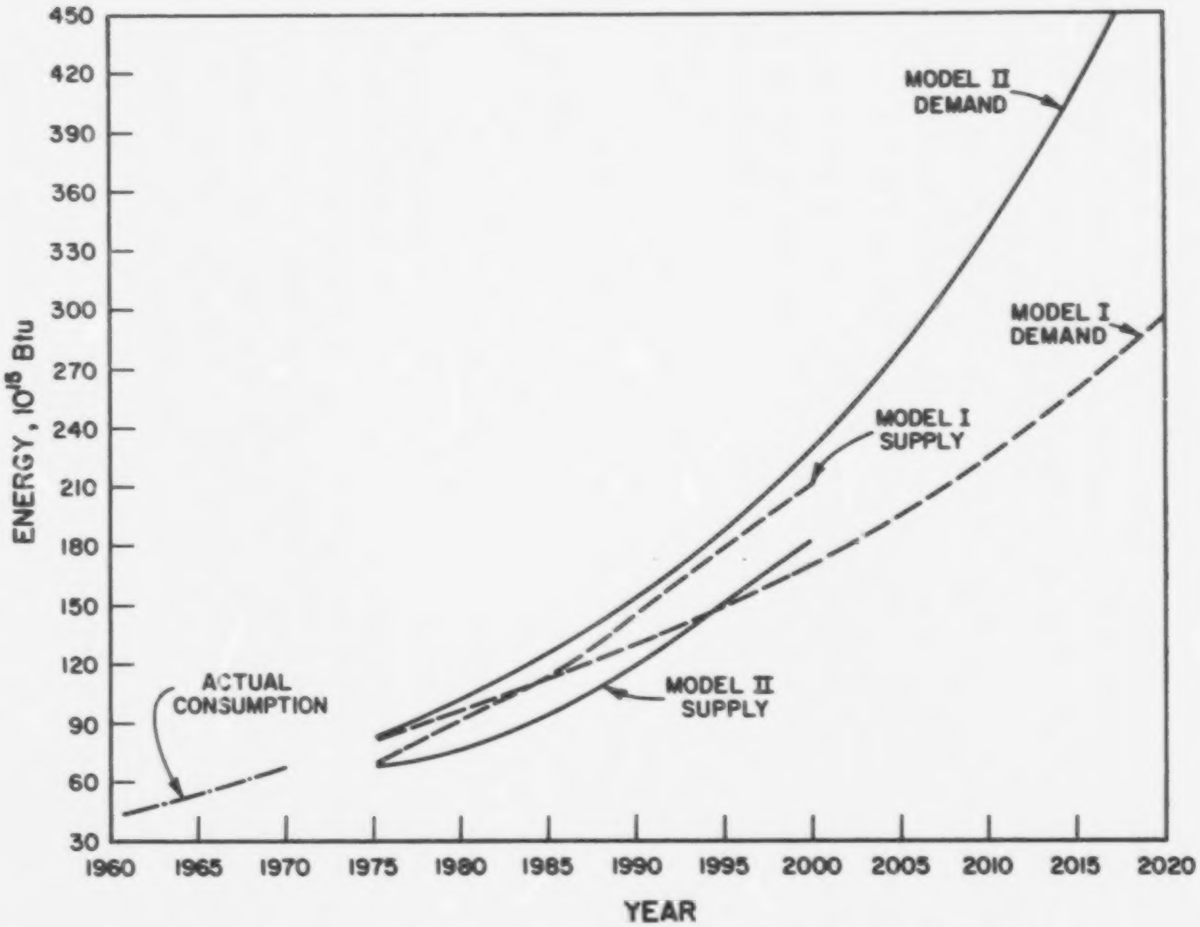

Figure 4-1. COMPARISON OF MODELS I AND II ENERGY DEMAND AND SUPPLY PROJECTIONS

Table 4-8. MODEL II PROJECTED ENERGY DEMANDS

	1971	1975	1980	1985	1990	2000	2020
	10^{15} Btu						
Total Energy Demand	68.7	82.9	101.1	125.2	153.4	228.2	500.5
Less Projected Nuclear, Geothermal, and Hydropower Supplies	3.4	6.5	12.8	24.6	32.2	57.6	228.4
	65.3	76.4	88.3	100.6	121.2	170.6	272.1
Probable Demand of Market Segments to be Met by Fossil Fuels (Supplies Included)							
Transportation	16.6	19.1	22.4	25.4	30.2	41.3	66.2
Residential and Commercial	13.7	16.0	18.5	20.9	24.8	34.0	54.4
Industrial	17.7	20.8	24.1	27.3	32.3	44.2	70.8
Electrical	13.3	16.2	18.3	21.3	27.1	41.9	66.0
Other	4.0	4.3	5.0	5.7	6.8	9.2	14.7
	65.3	76.4	88.3	100.6	121.2	170.6	272.1
Imported Supplies Included in Probable Demand							
Oil	7.6	16.2	23.3	30.1	35.8	51.1	115.0
Gas	0.8	1.3	2.8	4.0	5.4	8.3	21.0
	8.4	17.5	26.1	34.1	41.2	59.4	136.0
Domestic Supplies Included in Probable Demand (Oil, Gas, and Coal)	56.9	59.9	62.2	66.5	80.0	111.2	136.1

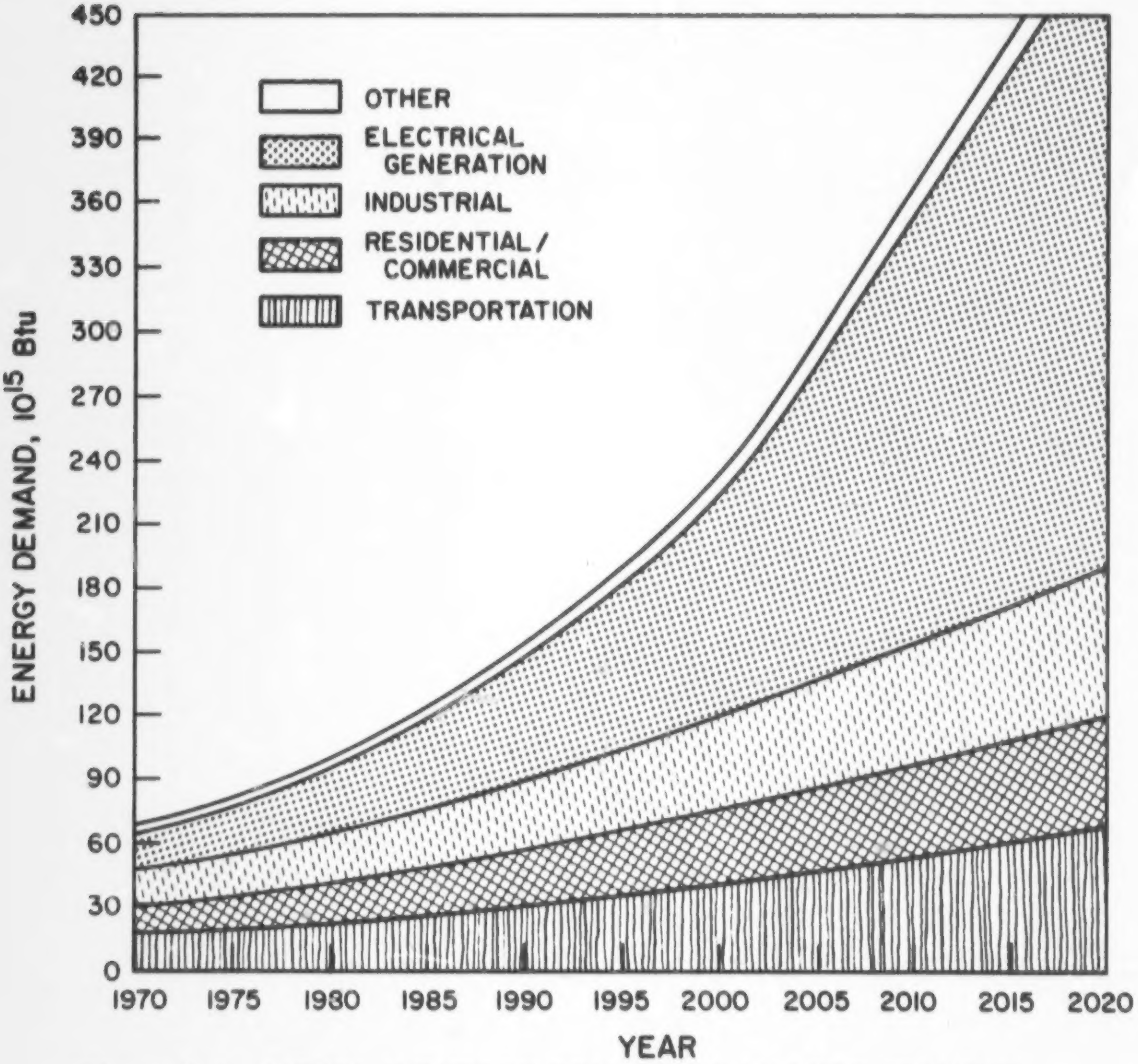

Figure 4-2. MODEL II ENERGY DEMAND BY MARKET SEGMENT (All Nuclear to Electricity Generation)

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Table 4-9. MODEL II RESIDENTIAL AND COMMERCIAL ENERGY SUPPLY AND DEMAND

	1971	1975	1980	1985	1990	2000	2020
	10^{15} Btu						
Total Demand	13.7	16.0	18.5	20.9	24.8	34.0	54.4
Supply							
Oil (21% of Supply)							
Imported	1.6	3.4	5.1	6.7	8.4	12.3	20.0
Domestic	4.8	4.5	5.1	5.0	5.3	5.1	5.0
Total Oil	6.4	7.9	10.2	11.7	13.7	17.4	25.0
Gas (31.1% of Supply)							
Imported	0.2	0.4	0.9	1.2	1.7	2.6	4.0
Domestic	6.9	6.6	5.9	5.4	5.4	5.3	6.0
Total Gas	7.1	7.0	6.8	6.8	7.1	7.9	10.0
Coal (2.3% of Supply)							
Domestic	0.3	0.2	0	0	0	0	0
Total (Excluding Electricity)	13.8	15.1	17.0	18.5	20.8	25.3	35.0

Table 4-10. MODEL II INDUSTRIAL ENERGY SUPPLY AND DEMAND

	1971	1975	1980	1985	1990	2000	2020
	10^{15} Btu						
Total Demand	17.7	20.8	24.1	27.3	32.3	44.2	70.8
Supply							
Oil (17.5% of Supply)							
Imported	1.3	2.8	4.2	5.5	6.9	10.3	16.0
Domestic	4.0	3.8	4.2	4.2	4.4	4.2	4.0
Total Oil	5.3	6.6	8.4	9.7	11.3	14.5	20.0
Gas (35.5% of Supply)							
Imported	0.3	0.5	1.0	1.4	1.9	2.9	4.0
Domestic	7.8	7.5	6.8	6.4	6.2	6.1	6.0
Total Gas	8.1	8.0	7.8	7.8	8.1	9.0	10.0
Coal (35.7% of Supply)							
Domestic	4.3	5.7	6.9	8.7	12.0	20.5	35.0
Total (Excluding Electricity)	17.7	20.3	23.1	26.2	31.4	44.0	65.0

Table 4-11. MODEL II C
SUPPLY AN

	1971	1
Total Demand	3.7	
Supply		
Oil(0.6% of Supply)		
Imported	Negl	
Domestic	0.2	
Total Oil	0.2	
Gas (15.8% of Supply)		
Imported	0.1	
Domestic	3.5	
Total Gas	3.6	
Coal (0.0% of Supply)	0	
Total (Excluding Electricity)	3.8	

Table 4-12. MODEL
SUPPLY A

	1971	
Total Demand	16.6	1
Supply		
Oil (54.7% of Supply)		
Imported	4.1	
Domestic	12.5	1
Total Oil	16.6	2
Gas (Negligible % of Supply)		
Imported		
Domestic		
Total Gas	Negl	N
Coal (0.1% of Supply)		
Domestic	Negl	N
Total (Excluding Electricity)	16.6	2

DEL II OTHER USES ENERGY
PLY AND DEMAND

1971	1975	1980	1985	1990	2000	2020
			10^{15} Btu			
3.7	4.3	5.0	5.7	6.8	9.2	14.7
Negl	0.1	0.15	0.2	0.2	0.3	0.3
0.2	0.1	0.15	0.1	0.2	0.2	0.2
0.2	0.2	0.3	0.3	0.4	0.5	0.5
0.1	0.2	0.5	0.6	0.8	1.3	1.2
3.5	3.4	2.8	2.7	2.8	2.7	2.4
3.6	3.6	3.3	3.3	3.6	4.0	3.6
0	0	0	0	0	0	0
3.8	3.8	3.6	3.6	4.0	4.5	4.1

MODEL II TRANSPORTATION
PPLY AND DEMAND

	1971	1975	1980	1985	1990	2000	2020
				10^{15} Btu			
	16.6	19.1	22.4	25.4	30.2	41.3	66.2
	4.1	8.9	13.2	17.4	21.9	32.3	54.0
	12.5	11.8	13.2	13.2	13.8	13.3	13.0
	16.6	20.7	26.4	30.6	35.7	45.6	67.0
y)							
	Negl	Negl	Negl	Negl	Negl	Negl	Negl
	Negl	Negl	Negl	Negl	Negl	Negl	Negl
	16.6	20.7	26.4	30.6	35.7	45.6	67.0

Table 4-13. MODEL II ELECTRICITY CONVERSION ENERGY UTILIZATION

	1971	1975	1980	1985	1990	2000	2020
				10^{15} Btu			
Nuclear	0.5	3.5	9.3	20.6	27.7	52.1	218.4
Hydro and Geothermal	2.9	3.0	3.5	4.0	4.5	5.5	10.0
Oil Consumption	1.8	2.3	2.3	2.3	2.3	2.3	2.0
Gas Consumption	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Coal Consumption	7.5	9.9	12.0	15.0	20.8	35.6	60.0
Total	16.7	22.7	31.1	45.9	59.3	99.5	294.4
Electricity Produced	5.8	7.9	10.9	16.1	20.8	34.8	103.0

models also serve to inform the reader about the quantities of energy consumed in various markets, and the magnitude of the quantities involved in meeting the needs of the U.S.

Under Model II conditions, even with imports, the residential, commercial, and industrial demands are not met, but a sizable importation of oil and gas would allow the transportation demands to be met. At the same time, there is extensive utilization – primarily of coal and nuclear heat – for the generation of electricity (or the production of a synthetic fuel), as shown in Table 4-13. Sector shortfalls without imports are shown in Table 4-14 for the various market sectors, excluding transportation.

Table 4-14. MODEL II SHORTFALLS (With No Imports) BY SECTOR IN ELECTRICITY SUPPLY

	1975	1980	1985	1990	2000	2020
				10^{15} Btu		
Transportation Shortfall	7.3	9.2	12.2	16.4	28.0	53.2
Residential/Commercial	4.7	7.5	10.3	14.1	23.6	43.4
Industrial	3.8	6.2	8.2	9.7	13.4	25.8
Other	0.8	1.9	2.7	3.8	6.3	12.0
Total Deficits (Less Transportation)	9.3	15.6	21.0	27.6	43.4	81.2
Electricity (or Synthetic Fuel Available)	7.9	10.9	16.1	20.8	34.8	103.0
Electricity (or Synthetic Fuel) Available for Transportation	Nil	Nil	Nil	Nil	Nil	21.8

As shown in Table 4-14, the available supply of electricity would be consumed in its entirety, and the U. S. would not be energy independent because serious shortfalls would still exist.

Some electricity would be available to reduce importation of energy for transportation in 2020, when a potential surplus from the other market segments would be available. If the priorities established for the model were changed, the energy necessary for conversion (or the fuel supply for electricity generation) could be diverted to transportation. As a result, the transportation segment alone could become energy independent. For example, if the industrial sector is forced to import more fuel (lower its priority) to meet its energy supply deficit, some of the fuels for generating electricity would be available for transportation. The release of coal, otherwise committed to the generation of electricity, for chemical fuel synthesis would enhance the energy supply situation appreciably because a significant part of the waste heat produced in the conversion of energy to electricity would no longer be wasted. On the other hand, at least this much energy is wasted in the use of a thermal (combustion) engine versus electricity in a motor-powered automobile. Model II indicates that a) energy supplies must be imported at least until 2020, b) a way must be found to utilize coal or nuclear heat in a more efficient manner (e. g., to synthesize chemical fuels, rather than to generate electricity), or c) a condition of unsatisfied demand in one or more market sectors must be tolerated.

In summary, under the conditions and assumptions of Model II, the U. S. cannot achieve energy independence prior to 2020. This situation is in direct contrast to the one described in Model I. In Model II, the overall demand for energy in the U. S. is expected to increase at an annual rate of 4.4%, 1971-85; 4.1%, 1985-2000; and 4.0%, 2000-2020. Supplies of energy from domestic sources are expected to increase at an annual rate of 2.9% from 1971 to 1985, 3.9% from 1985 to 2000, and 4.0% from 2000 to 2020. Not until the period 2000-2020 will the annual rate of growth in the amount of domestic energy supplied match the annual rate of growth for demand. We should point out that nuclear, geothermal, and hydropower energy account for about 36% of the total domestic supply in 2000 and about 65% in 2020. These energy forms, under present technology, cannot be used for applications other than the generation of electricity.

4.3 Automotive Sector

In this section, particular emphasis is placed on determining the quantity of energy required to satisfy the demand within the transportation sector. The assumptions in Models I and II are carried over into this discussion and are supplemented by data from studies prepared by the Department of the Interior and DOT.[1] Only a portion of the transportation sector is of concern here, i.e., automobiles, trucks, and buses. The energy requirements of the remainder of the sector — aircraft, ships, and trains — are beyond the scope of this study.

The DOT publication reported transportation energy consumption in terms of energy source and mode of operation. Its findings are summarized in Table 4-15, which shows that auto, truck, and bus modes of operation consumed almost 75% of the energy total for the sector.

Table 4-15. DISTRIBUTION OF ENERGY CONSUMPTION* IN TRANSPORTATION BY MODE IN 1969 (Source: Ref. 1)

Mode		Energy Source	Percent
Automobile		Oil	51.2
Truck	Intercity freight	Oil	9.1
	Urban freight	Oil	5.1
	Service and utility	Oil	8.2
Bus	Intercity	Oil	0.2
	Urban and school	Oil	0.5
Subtotal			74.3
Railroad	Intercity passenger	Oil and wayside electric	0.1
	Freight	Oil	3.6
	Subway	Wayside electric	0.1
Pipeline	Freight	Oil and gas, mostly	2.0
Airline	Passenger	Oil	11.4
	Freight	Oil	2.6
Water	Passenger	Oil	0.2
	Freight	Oil	5.8
Total			100.1

* Overall transportation consumption: 15 X 10^{15} Btu/yr.

The following conclusions, which were presented in the DOT study, are in agreement with the projections for Models I and II –

- Transportation consumes about 25% of total U.S. domestic energy supply and is expected to do so at the same rate in the foreseeable future.
- Transportation is a major user of petroleum. Fifty-five percent of the petroleum consumed in the U.S. is used by transportation. This fraction is projected to increase to 60% in the mid-1980's.
- Transportation is intensively dependent on petroleum; more than 98% of the transportation energy consumed is from a petroleum-based energy source.

The Department of the Interior also has projected energy demand for the U.S. including consumption within the transportation sector. This study is in close agreement with the DOT[1] and NPC[4] studies in that during the period ending in 1985, transportation is expected to account for about 23% of the total U.S. consumption. The assumptions used by the Department of the Interior are as follows:

- Population of the U.S. will increase at an annual rate of about 1%.
- Industrial production is expected to increase 5% on an annual basis up to 1980, after which the growth rate will decline to 4.4% to 1985.
- All fuel supply limitations are taken into consideration, resulting in a forecast of consumption, rather than a forecast of unrestrained demand.
- Energy prices are expected to rise faster than prices for other commodities.

The NPC has found that changes in automotive fuel consumption, for the period ending in 1985, correlate very closely with real GNP in spite of changes in demographic factors, driving habits, types of vehicles, fuel quality, highway conditions, and alternative forms of transportation. This finding led to the following conclusions by the NPC for the near-term future:

- The consumer regards most automobile mileage as fairly essential, although he may change the type of car he drives.
- The cost of oil and gasoline is only about one-fourth of the total cost of operating a private automobile.
- In the case of commercial transportation, such as trucks, railroads, and airlines, fuel requirements are an essential element of the business and are not expected to change only on the basis of cost.

The three transportation forecasts are presented for comparison in Table 4-16, which shows that the estimates are within 10% of each other, which is quite respectable considering the length of the time period. For purposes of this study, the trends shown in Table 4-16 are assumed to continue to 2020.

Table 4-16. COMPARISON OF DOT, DEPARTMENT OF THE INTERIOR, AND NPC ENERGY DEMAND FORECASTS

	Base Years			Forecast Years			
	1969	1970	1971	1975	1977	1980	1985
	10^{15} Btu						
Total U.S. Energy as Demand Projected by –							
NPC*	--	67.8	--	80.5	--	95.7	112.5
DOT†	59.6	--	--	--	86.2	--	119.9
Department of the Interior	--	--	69.0	80.3	--	96.0	116.6
Transportation Sector Demand –							
NPC	--	16.3	--	19.3	--	23.0	26.7
DOT	14.9	--	--	--	21.5	--	30.0
Department of the Interior	--	--	17.0	19.1	--	22.8	27.1

* Model I.

† Inferred from report assumption, i.e., transportation consumption equivalent to 25% of total demand.

4.3.1 Model for Automotive Sector

The following conclusions, which relate specifically to energy consumption by the modes of transportation with which we are concerned, are from NPC data:

- Although fuel cost is not the major item in the total cost of owning and operating a car, it is an out-of-pocket and highly visible cost. Therefore, it is likely to carry a disproportionate weight in consumer decisions.

- **The higher cost of motor fuel is one of a package of economic inducements that would cause consumers to purchase "economy" cars.**

- **In commercial transportation, the cost of fuel is important enough to play a significant role in an operator's decision on the type of new equipment purchased and the timing of the purchase.**

- **In 1970, the ratio of standard cars to economy cars was estimated to be 86:14; by 1985, the same ratio is expected to be 50:50. The change in the ratio is due to increased fuel prices, which, in turn, induce the purchase of smaller vehicles.**

All these assumptions and conclusions are incorporated into the total demand of the transportation sector. In Table 4-17, the automotive (auto, truck, bus) portion of the total sector demand has been segregated, and as shown, 55% of the projected domestic supplies of conventional petroleum, as well as oil shale and coal liquefaction products, will not be adequate to support automotive requirements.

As stated previously, the condition of oversupply attributed to Model I is in the form of coal and nuclear energy that cannot be used in conventional form as fuel for automobiles. Clearly, there is a need for an alternative fuel, synthesized from some resource other than crude oil, or the importation of petroleum products must continue during the time frame of this study, if transportation needs are to be satisfied.

Table 4-17. MODEL I TRANSPORTATION ENERGY SUPPLY AND DEMAND AND AUTOMOTIVE DEFICIT

	1970	1975	1980	1985	2000	2020
	10^{15} Btu					
Total Sector Demand	16.3	19.4	23.0	26.7	40.4	70.1
Automotive Demand* (75% of Total)	12.2	14.5	17.2	20.0	30.3	52.6
Supply						
Oil (54.7% of Total Domestic Supply)	11.5	13.0	15.4	19.0	26.2	27.7
Automotive Deficit	0.7	1.5	1.8	1.0	4.1	24.9

* Automobiles, trucks, and buses; the remaining demand is attributable to aircraft, ships, and trains.

4.3.2 Model II for Automotive Sector

The energy demand and supply projections from Model II also can be used for determining the automotive needs within the transportation sector. In contrast to Model I, Model II represents a situation in which a permenent imbalance exists between the supply and demand for energy. Imports of energy, in the form of petroleum and natural gas, are expected to occur throughout the time period of this study, whereas Model I showed a potential surplus of energy supply in the form of coal and nuclear power commencing by about 1985.

The same assumptions and conclusions for Model I that pertain to the characteristics of the automotive segment of the transportation sector are carried over into this assessment of Model II energy demand and supply conditions. In Model II, a greater rate of increase in the overall demand for energy is accompanied by somewhat lower levels of domestic supply capability. As in the case of Model I, Model II transportation energy supply is the lowest in terms of priority ranking. The demand and supply of energy in the transportation sector are shown in Table 4-18; total transportation demand for energy does not differ significantly from the demand shown for Model I. However, the deficit quantity (based on 55% of domestic petroleum) is much greater in Model II, resulting in a need for more alternative sources of energy at an earlier time.

Table 4-18. MODEL II TRANSPORTATION ENERGY SUPPLY AND DEMAND AND AUTOMOTIVE DEFICIT

	1971	1975	1980	1985	1990	2000	2020
	10^{15} Btu						
Total Sector Demand	16.6	19.1	22.4	25.4	30.2	41.3	66.2
Automotive Demand* (75% of Total)	12.4	14.3	16.8	19.1	22.6	30.9	49.6
Supply							
Oil (54.7% of Total Domestic Supply	12.5	11.8	13.2	13.2	13.8	13.3	13.0
Automotive Deficit From Domestic Supply	--	2.5	3.6	5.9	8.8	17.6	36.6

* Automobiles, trucks, buses; the remaining demand quantity is attributable to aircraft, ships, and trains.

Essentially the same conclusions can be reached in the application of Models I or II; i.e., an alternative fuel must be developed for use in automobiles if this energy-consuming segment is to achieve independence from imported sources.

4.4 Model III

The projection of energy supply and demand in the U.S. at present is a particularly difficult task because of the uncertainty of national energy policy and the future availability of energy from conventional sources. A number of excellent studies have been published by authoritative sources, and we have used some of these as bases for Models I and II.

The 1973/74 Arab embargo of oil exports to the U.S., the unprecedented and unanticipated increases in energy costs, and the recent allocation and conservation measures undertaken by the Government and by fuel users of all kinds illustrate that even the most recent energy projections can quickly become obsolete. That oil embargo reduced the projected energy supply in the U.S. for 1974 by approximately 4%, so energy demand was curtailed by a corresponding amount. The resulting curtailment and conversion measures undoubtedly will have a far-reaching effect on the U.S. energy economy for many years to come.

As a result, we decided to modify available energy demand projections to determine, to some degree, the effects of these curtailment and conservation measures on transportation energy consumption and the attendant need for an alternative automotive fuel. Although Model III is not used as a basis for alternative fuel selection in the remainder of this study, its introduction does convey the possibility of a set of conditions occurring in which an alternative fuel is not required until at least after 1990 (in contrast to Models I and II).

Efforts were concentrated on the automobile segment of the transportation market sector. Time and budget limitations did not permit expanding Model III to the individual sectors of the economy, and the time period considered extends only to 1990. Model III demand projections are compared with Models I and II in Table 4-19.

Table 4-19. U.S. GROSS ENERGY DEMAND ACCORDING TO MODELS I, II, AND III

Year	Model I	Model II	Model III
	10^{15} Btu		
1975	80.3	82.9	80.3
1980	95.7	101.5	91.5
1985	112.5	125.2	105.9
1990	--	153.4	122.8
2000	170.3	228.2	--
2020	295.7	500.5	--

The automobile plays a very important role in the U.S. economy. Approximately 130 million motor vehicles are currently in operation in the U.S.; of these, about 95 million are automobiles. By age classification, approximately 60% are less than 5 years old, and less than 15% are more than 9 years old. During the last 5 years, between 8 and 9 million automobiles were domestically manufactured each year. Approximately 7 million are produced for the replacement market, and the remainder are additions to the overall automobile population. An average late-model, full-size automobile is driven 10,000 miles per year and consumes about 833 gallons of gasoline on a yearly basis. Further, an estimated 80% of the families in the U.S. own at least one automobile, whereas 30% own two or more.

For the majority of these persons, the automobile is the means of transportation for getting to and from places of employment. Rapid-transit systems provide service only to and within a few of the largest metropolitan areas. In many instances, they are not completely adequate. Bus systems provide transportation within medium-size cities, but a commuter service is a rarity. Today, as much as 41% of the gasoline consumed in privately owned automobiles is for travel to and from work. As stated previously, a significant increase in the number of cars per household has taken place because about 40% of the households in the U.S. have two or more wage earners.

The population growth in suburban areas and in outlying rural areas also has greatly increased the dependence upon the automobile to satisfy the essential family needs. Heavy reliance is placed upon the automobile for transportation to doctors, shopping, school transportation, and church. Automobile utilization to satisfy essential needs is almost as extensive as transportation to and from work. This would indicate that about 80% of the gasoline consumed in privately owned automobiles is for essential purposes.

During the 1960's, the general purchasing pattern was toward larger automobiles with larger engines and more accessory equipment, resulting in fewer miles traveled per gallon of gasoline. Essentially, vehicle mileage is a function of vehicle weight. Over the last year, the unit consumption rate, i.e., miles/gal of gasoline, dropped approximately 11% from 13.7 to 12.2 miles/gal.

The Clean Air Act of 1970 dictated that automobile emissions must be reduced. At the time, there was no known technology capable of reducing emissions to the desired level as long as gasoline contained lead additives.

The Government, in its desire to reduce automotive emissions, decided the most appropriate action would be to make lead-free (or very low lead) gasoline available from U.S. refineries. After the lead had been removed, present technology could be used to reach the desired level of automobile emissions. The equipment installed in cars for reducing emissions has been a factor in the recent increase in fuel consumption.

Increased fuel prices also are expected to alter automobile fuel consumption patterns. Doubling the price of gasoline is equivalent to about 4% of the total income for the average U.S. household. Implicit in this conclusion is the premise that driving habits will not change. In the very short run, 2-4 years, this premise is reasonably accurate because, as previously stated, approximately 80% of the driving done by the average American is essential to sustain the current standard of living. In the longer term, doubling the price of gasoline will affect demand. In purchasing replacement vehicles, more attention is expected to be placed on vehicles that use less gasoline per mile driven. Such cars are currently available, and they are beginning to become popular.

Currently, the EPA is evaluating the consequences of introducing Federal legislation that will require automobile manufacturers to produce cars with improved fuel economy. The legislation would require that each year in the next decade, all new-vehicle gasoline consumption rates be improved from 6 to 8%/yr. If such action were taken within the next 2 years, total gasoline consumption in 1990 is estimated at about 1 million bbl/day less than current demand. To some extent, this increased mileage trend will occur by customer preference, because of higher fuel costs. By 1990, daily consumption could be in the range of 5.25-6.75 million bbl. Figure 4-4 reflects this projection of gasoline demand, along with several scenarios that could shift the forecast quantity.

4.4.1 Case A

For this case and all others, a constant annual production of 10 million new automobiles was assumed. (Imports were not considered because, on the average, they exceed the minimum fuel consumption quantities considered herein.) In this case, the automobile population is assumed to increase by 1 million units per year through 1990. Although this growth is only 60% of the present rate, evaluation of the population age profile and changes in social patterns indicate that this rate has a high probability of occurrence. Implicit with this growth rate is a replacement rate of 9 million units per years, based on a current automobile population of 130 million.

Further, all new vehicles are assumed to achieve an average of 17 miles/gal of gasoline, in contrast to the current average of about 12 miles/gal. All other driving habits will remain the same.

Under these prescribed conditions, the total gasoline consumption in 1990 would be 5.75 million bbl/day.

4.4.2 Case B

The only difference between Cases A and B is that the automobile population growth in Case B continues at a rate of 2 million/yr, instead of the 1 million increase assumed for Case A. For this condition, the total gasoline consumption in 1990 would be 6.75 million bbl/day, which represents an upper bound for Model III.

4.4.3 Case C

This case assumes the introduction of a diesel automobile capable of achieving 25 miles/gal in 1981. (Automobiles of this type are currently available.) During the first 3 years, production of these automobiles is assumed to be 2 million units per year, with 6 million produced per year in 1984. These new diesel-powered vehicles will replace some of the lower mileage automobiles. Maximum new car production is maintained at 10 million new units per year. For this case, total gasoline and diesel fuel consumption in 1990 would be 5.25 million bbl/day.

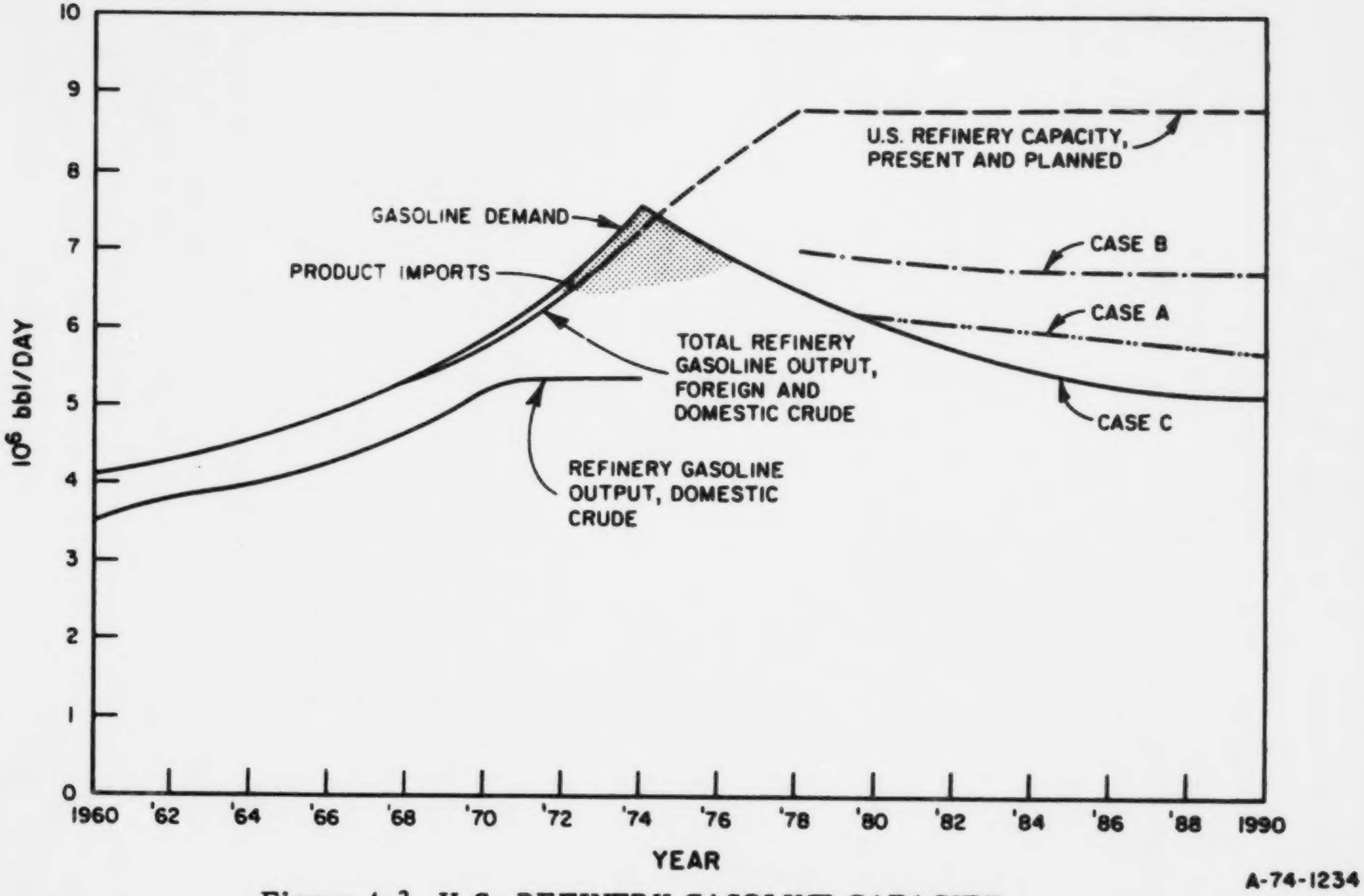

Figure 4-3. U.S. REFINERY GASOLINE CAPACITY

The shaded area in Figure 4-3 is the estimated decrease in gasoline availability brought about by the recent Arab oil embargo against the U.S. The impact of the embargo has not been fully quantified; nevertheless, it has placed severe restraints on the amount of gasoline temporarily available to satisfy demand.

Figure 4-3 also reflects new refinery expansion planned through 1977. (This is in terms of gasoline production, which, historically has been about 48% of total refinery capacity.) If the projected demand schedule for gasoline is valid, an eventual incremental gasoline-refinery capacity of 1.6 million bbl/day would be available for the production of other products. The most likely candidate for this additional capacity would be distillate fuels.

In summary, the most probable gasoline demand in 1990 according to Model III will be about 6 million bbl/day (essentially Case A, allowing for some degree of slippage in the production of smaller vehicles), in contrast with the 1974 demand estimate of 7.5 million bbl/day.

4.5 References Cited

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4. National Petroleum Council, U.S. Energy Outlook: A Report of the National Petroleum Council's Committee on U.S. Energy Outlook. Washington, D.C., December 1972.

5. FUEL SYNTHESIS TECHNOLOGY

The resource base assessment (Section 3) and the energy demand and supply Model I (Section 4) indicate that the domestic energy sources useful* for automotive fuel production are coal, oil shale, nuclear energy (fission), and possibly solar energy and waste materials (followed by biomass conversion). These choices are partially evident from Table 3-2. Justification of these energy resource choices is presented in Section 10. Other energy sources are inadequate because 1) they do not exceed the 25-year, 15% transportation demand requirement of about 108 quadrillion Btu (as fuel) and the annual requirement of 3-6 quadrillion Btu (as fuel), or 2) the energy production technology constitutes a moderate or severe technology gap (breeder fission and nuclear fusion). However, other energy sources (winds, tide, geothermal heat, etc.) deserve development as contributors to the overall U.S. energy supply, because local or limited use of these unconventional sources may result indirectly in more (conventional) fuel being available for transportation.

5.1 Fuel Synthesis From Coal

Considerable effort is being directed toward developing processes that convert coal to clean fuels – gaseous, liquid, or solid. As shown in Figure 5-1, gasification of coal occurs via two routes. The first route produces clean gas of either medium heating value (250-550 Btu/CF) or high heating value (950-1000 Btu/CF). The latter is a supplement to pipeline-quality natural gas (SNG). The second route to clean gas produces only low-heating-value (100-250 Btu/CF) gas, because the gas contains considerable nitrogen. The nitrogen is introduced when air is used to furnish the heat required for the gasification reactions.

Clean liquids or clean solids are produced from coal by three principal routes. In the first route, clean gas containing appropriate proportions of carbon monoxide and hydrogen (synthesis gas) is converted by the Fischer-Tropsch Process to hydrocarbon oil. The second route involves heating the coal to drive out the naturally occurring oils (pyrolysis) and

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* "Useful" means a potential supply sufficient to exceed about 15% of the annual transportation demand.

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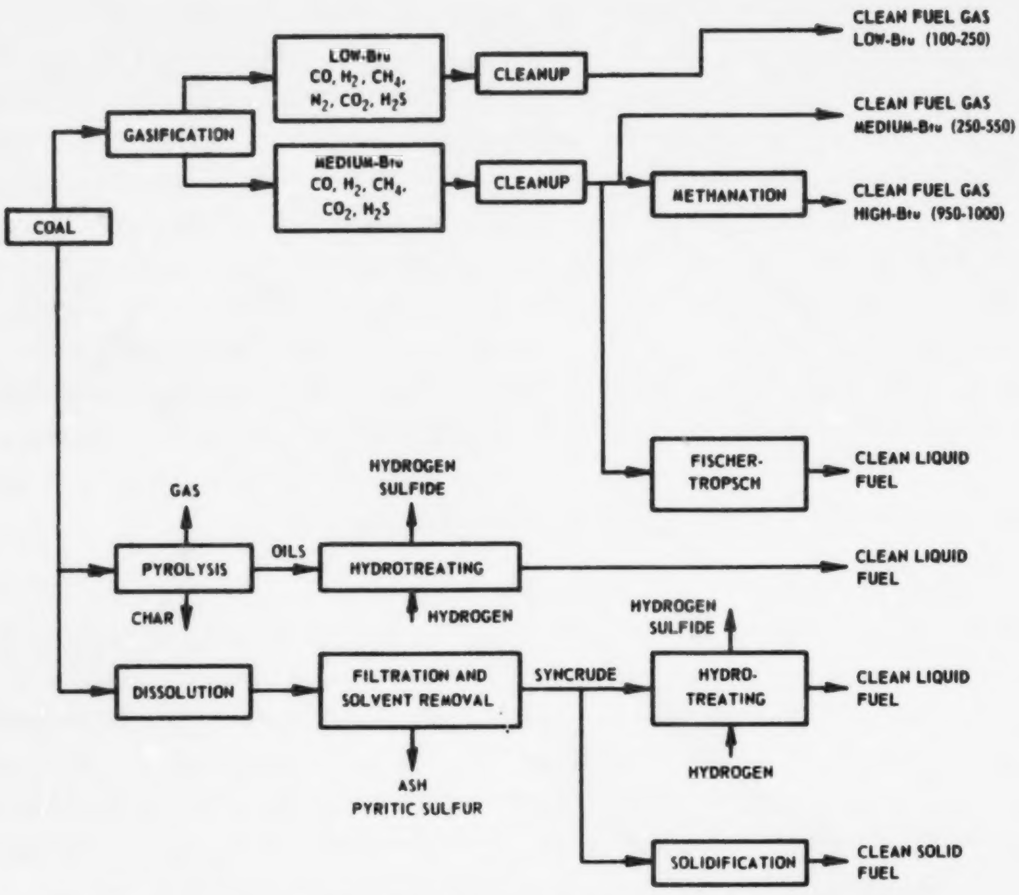
CLEAN FUEL GAS
LOW-Btu (100-250)
LOW-Btu
CO, H_2, CH_4,
N_2, CO_2, H_2S
CLEANUP
GASIFICATION
CLEAN FUEL GAS
MEDIUM-Btu (250-550)
MEDIUM-Btu
CO, H_2, CH_4,
CO_2, H_2S
CLEANUP
METHANATION
CLEAN FUEL GAS
HIGH-Btu (950-1000)
COAL
FISCHER-TROPSCH
CLEAN LIQUID FUEL
HYDROGEN SULFIDE
GAS
PYROLYSIS
OILS
HYDROTREATING
CLEAN LIQUID FUEL
CHAR
HYDROGEN
HYDROGEN SULFIDE
DISSOLUTION
FILTRATION AND SOLVENT REMOVAL
SYNCRUDE
HYDRO-TREATING
CLEAN LIQUID FUEL
HYDROGEN
ASH
PYRITIC SULFUR
SOLIDIFICATION
CLEAN SOLID FUEL

Figure 5-1. PRODUCTION OF CLEAN FUELS FROM COAL

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then treating these oils with hydrogen for desulfurization and quality improvement. Pyrolysis processes produce significant quantities of by-product gas and char, which must be disposed of economically. The third route to clean liquid fuel involves dissolving the coal in a solvent and filtering out ashes, which include pyritic sulfur. After the solvent has been removed, the resulting heavy crude oil (syncrude) is treated with hydrogen (hydrotreating) to remove organic sulfur and, at the same time, to improve its quality. In one process, a solid fuel (SRC) is produced if the syncrude is allowed to cool before hydrotreatment.

Many processes produce synthesis gas, SNG, or liquid fuels from coal. Some processes are in commercial production, some are on a pilot-plant scale, and some are in the development stage. Tables 5-1 through 5-3 list processes for making SNG, liquid fuels, and synthesis gas from coal, respectively. The energy and/or material input, synthesized product, by-products, potential pollutants, and a description of each process are included.

Methanol can be considered a desirable fuel for automotive transportation. The processes for producing methanol from coal, SNG, naphtha, and heavy fuel oil are presented in Table 5-4. Ammonia has been considered as an automotive fuel for modern armies because it can be catalytically synthesized from nitrogen obtained from air and from hydrogen obtained from the electrolysis of water. Table 5-5 presents the processes for producing ammonia from coal, naphtha, SNG, and heavy oil. Hydrogen also has been tested as an alternative automotive fuel on a hydrogen car. The processes for producing hydrogen from coal (or oil shale) SNG, naphtha, and electrical energy are presented in Table 5-6.

Coal is considered a "dirty" fuel, principally because of its sulfur content. When coal is processed to produce desirable fuels, the sulfur goes into the liquid, gaseous, and solid material streams. The proportion of sulfur and other pollutants in the liquid products, gaseous products, and char depend on the process design, operating conditions, and methods of contacting solids and gases (cocurrent, countercurrent, entrained bed), etc. For example,

Table 5-1. PROCESSES FOR PRODUCING SNG (Methane) FROM COAL

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
355-390 billion Btu coal 4700-6500 tons O_2 19,200-28,800 tons steam at 500 psi 21,600-36,000 tons/hr feed water 60 MW power*	Lurgi Process[30]	Lock hoppers feed crushed coal to a moving-bed gasifier. A revolving grate feeds in O_2 and steam while removing ash. Oper.pressure is up to 450 psi. Exit gas temperature is between 700° and 1100°F. This process produced 970 Btu/SCF gas. Limited to noncaking coals.*(incl. both electric and steam drives)	250 billion Btu	15,600 tons high-pressure steam 960-1680 tons of tar-oil-naphtha 72-144 tons phenols	Relatively low off-gas temperature and countercurrent design increase appearance of tars, NH_3, etc., in waste quench liquor.
17,092 tons coal (12,401 Btu/lb) as a feed and fuel (also 347,217 kW power included in it)	HYGAS Process[35] (with electrothermal gasifier)	Dried coal is slurried with light oil and fed to a 2-stage fluidized-bed hydrogasifier operating at 1000-1500 psia. An electrothermal gasifier, oxygasifier, or a steam-iron process, using char from the 2nd stage of the HYGAS unit, produces hydrogen-rich gas which is supplied for gasification. Exit gas temperature is 600°F.	253 billion Btu or 262.5 million SCF	85,104 gal oil 52,452 gal C_6H_6 81 tons NH_3	For the pretreatment of caking coals, sulfur existing in the pretreatment off-gas must be removed.
16,237 tons coal (12,401 Btu/lb) as a feed and fuel (also 2930 tons O_2 included in it)	HYGAS Process (with oxygen gasifier)		247 billion Btu or 256.4 million SCF	76,470 gal oil 46,339 gal C_6H_6 72.4 tons NH_3	
20,381 tons coal (12,401 Btu/lb) as a feed and fuel (also incl. manufacture of H_2)	HYGAS Process (with steam-iron)		253 billion Btu or 261.4 million SCF	103,152 gal oil 63,910 gal C_6H_6 99 tons NH_3	

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Table 5-1, Cont. PROCESSES FOR PRODUCING SNG (Methane) FROM COAL

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
12,000 tons coal to gasifier (13,000 Btu/lb); 2400 tons coal (steam and O_2 production); 16 million gal water	Bi-Gas[15]	Coal is gasified with hydrogen. The resulting char (with O_2 and steam) produces the hydrogen-rich gas to sustain the hydrogasification process. The operating pressure is 1000 psia. Exit gas temperature is 1700°F. This process produces 950+Btu/SCF gas. Uses all U.S. coal.	250 million SCF pipeline gas (HHV (950 Btu/SCF)	--	Slagging gasifiers at high temperature minimize sulfur content of the ash. High off-gas temperatures should reduce tars, amines, phenols, etc., in the quench liquor.
13,200 tons coal (13,990 Btu/lb); 226.8 tons Na_2CO_3 (makeup) 1.36 billion SCF air; 31.104 million gal cooling water (makeup); 3.785 million gal BFW	Molten Salt[26]	O_2, steam, and coal are injected into a reactor and molten Na_2CO_3 catalizes gasification. Gasifier is operated at 400 psig and 1900°F. This process produces 900+ Btu/SCF gas. Uses all U.S. coal.	250 million SCF pipeline gas (914 Btu/SCF)	--	The sulfur is recovered during regeneration of molten salt.
14,220 tons coal (12,700 Btu/lb); 36.95 million lb h-p steam (includes production of 2770 million SCF O_2); 374.5 million gal cooling water; 25.92 million gal process water.	Synthane[1]	Coal is introduced into a single reactor which incorporates 3 processing steps; a free-fall O_2 steam pretreatment zone – a dense fluid-bed carbonizer, and a dilute fluid-bed gasifier. H_2-rich gas is produced by use of O_2 in the reactor. The process operates at 500 to 1000 psia. This process produces 900+ Btu/SCF gas. Uses all U.S. coal.	250 million SCF pipeline gas (HHV 927.1 Btu/SCF)	tar 501.6 tons NH_3 88.32 tons	Nature of pretreatment does not produce a separate, sulfur-laden stream.
29,850 tons coal (including fuel requirements)(7068 Btu/lb); 2250 tons makeup dolomite; 1,011 billion SCF air; 2,955 million gal BFW; 159.5 million gal cooling water	CO_2 Acceptor[5]	Coal is charged to a devolatilizer and is contacted at 300 psia with H_2-rich gas from a gasifier vessel. Lime or dolomite (the Acceptor) is added to both vessels where it reacts with CO_2. This process produces 950+Btu/SCF gas. Uses lignite and subbituminous coal	262.6 million SCF/day pipeline gas (HHV 953 Btu/SCF)	--	Sulfur treatment of the regenerator offgas is required.

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Table 5-2. PROCESSES FOR PRODUCING LIQUID HYDROCARBONS FROM COAL

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
1 ton coal 0.0383 ton coal fuel (10,630 Btu/lb) 7.6 kW power 600 gal water About 15-18,000 CF Hydrogen	H-Coal Process[21] by Hydrocarbon Research, Inc.	The coal is hydrogenated and converted to liquid and gaseous product in an ebullating bed reactor containing a cobalt-moly catalyst. The operating conditions are 2250-2700 psig and 850°F. H_2 is produced by partial oxidation of the residual oil and coal residue.	2.429 bbl of crude oil 25° API	3.24 million Btu gas 14.8 lb NH_3 Amount of S depends on type of coal	Product oil l must be hydrodesulfurized. Char contains sulfur.
1 ton coal (10,820 Btu/lb)	CSF Process[11] by Consolidation Coal Co.	Coal is slurried with solvent and heated to extraction temperature at 765°F and at 150 psig. Solids are sent to a low-temperature carbonization unit. Liquid passes through solvent recovery unit. Tar and heavy residue is hydrotreated at about 800°F and 3000 psig.	21.9 gal naphtha 58°API 63.6 gal fuel oil 10.3°API	3400 SCF gas (933 Btu/SCF) 11 lb ammonia	Syncrude products must be hydrodesulfurized. The gas coming out from the low-temperature carbonization unit must be treated to remove H_2S.
1 ton dry coal (12,600 Btu/lb) 550 lb steam 2300 SCF natural gas to first stage	COED Process[20] by FMC Corp.	Coal is pyrolyzed in four stages. Coal is subjected to increasing temperatures of 600°, 850°, 1000°, 1600°F in first to fourth stages, respectively. The pressure of the operation is between 6-10 psig. Eff. of the process depends on process to desulfurize char.	43.7 gal oil (−4°API)	8100 CF gas (480 Btu/SCF) 1177 lb char (11,870 Btu/lb) 7.1 gal liquor	The removal of sulfur is required from product liquid, gas streams, and char.
1 ton coal (8750 Btu/lb) 11.6 kW Power, 1300 gal water	Synthine Process[10] by U.S. Bureau of Mines	Coal is converted to syngas, then ($CO + H_2$) is converted into liquid hydrocarbons by using suitable catalyst. The conditions of operation are 200-400 psi and about 600°F.	54.1 gal gasoline 17.8 gal LPG	3.1 gal phenol	Sulfur is removed only from the gas stream.

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Table 5-3. PROCESSES FOR PRODUCING SYNTHESIS GAS (Hydrogen and Carbon Monoxide) FROM COAL[12]

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
1 ton coal 6470 SCF O_2 1687 lb h-p steam 210 gal process water	Lurgi Pressure Gasifier	Operated at 450 psi and 1400°-1600°F High-ash coal (7500 Btu/lb)	46,000 CF raw gas 30,000 CF purified gas (400 Btu/SCF)	0.5 gal oil 2.9 gal tar 321 gal gas liquor 1551 lb LP steam	Relatively low off-gas temperature and countercurrent design increase appearance of tars, NH_3, etc., in waste quench liquor.
1 ton coal 20,376 SCF O_2 708 lb LP steam 83.8 kWhr	Koppers-Totzek Process	Operated at 1 atm and 1830° to 2370°F Carbon conversion 96% High-ash coal	56,600 CF raw gas (277 Btu/SCF)	2374 lb steam NO 4.5 ppm	Very high off-gas temperature precludes the formation of any compound less stable than H_2, CO, CO_2.
1 ton coal 12,271 SCF O_2 3100 lb LP steam	Winkler Generator	Operated at 1 atm and 1470° to 1650°F Carbon conversion 80% Low-ash coal (976 Btu/lb)	52,200 CF raw gas (288 Btu/SCF)	1500 lb steam at 17.6 atm	High gasifier temperature ensures that all tars and heavy hydrocarbons are reacted.
1 ton coal 14,050 SCF O_2 261 lb LP steam	Rummel Single-Shaft Slag Bath Gasifier	Operated at 1 atm and 1830°F (coal 10,025 Btu/lb) Carbon conversion 99%	49,300 CF CO + H_2	2064 lb steam	The reactants pass through slag, consequently off-gas contains relatively high amounts of ash.
1 ton coal 19,950 SCF O_2 2390 lb LP steam	Flesch Demag Generator	Operated at 1 atm and 570°-750°F High-ash coal (13,400 Btu/lb) Pilot-plant scale	65,400 CF CO + H_2	987 lb steam	Process is good for low reactivity fuels and fuels with a low ash-fusion temperature.
1 ton coal 18,380 SCF O_2 1680 lb LP steam	Würth Gasifier	Operated at 1 atm and 715°F, coal (12,375 Btu/lb)	71,900 CF CO + H_2	--	--
1 ton coal 19,160 SCF O_2 610 lb steam	U. S. B. M. Gasifier	Operated at 20 atm and high temp. Coal (12,950 Btu/lb) Pilot plant	51,800 CF CO + H_2	1539 lb steam	Heat losses in the gasifier are high. Produced gas contains less heavy hydrocarbons because of high temperature of the gasifier.
1 ton coal 19,950 SCF O_2 1750 lb steam	B&W-DuPont	Operated at 1 atm and 2190°F, Coal (14,480 Btu/lb)	59,000 CF CO + H_2	>3500 lb steam	Two high-temperature reaction zones ensures that all tars and heavy hydrocarbons are reacted.
1 ton coal 20,570 SCF O_2 3000 lb steam	IGT Gasifier	Operated at 5 atm and 2700°F, Coal (12,140 Btu/lb) Pilot-plant scale *Cold gas efficiency	62,900 CF CO+ H_2	--	Very high off-gas temperature precludes the formation of any compound less stable than H_2, CO, CO_2.

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Table 5-4. PROCESSES FOR METHANOL PRODUCTION

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
Coal to Methanol[6]					
2 tons of coal (8500 Btu/lb) About 1 ton of oxygen	Use any gasifier to make synthesis gas. (Oxygen requirement varies with the process)	Coal is gasified and converted to CO + H_2-rich gas. The gas can be converted to methanol in presence of catalyst at about 40-50 atm and 200° to 300°C	1 ton of methanol	Small amount of higher alchol is produced	**Sulfur removal problems are similar to coal gasification problems.**
SNG to Methanol[18]					
30.2 million Btu feed and fuel 75 kWhr power 7300 SCF CO_2 144,016 feed water 13,200 gal cooling water	Lurgi Low-Pressure Process	Natural gas is reformed to synthesis gas. The synthesis gas is compressed to 40-50 atm and converted to methanol in presence of copper-containing catalyst at 200°-300°C	1 ton methanol	Small amount of higher alcohol is produced	**Minimum pollution problems.**
Coal-or Oil Shale-Derived Naphtha to Methanol[18]					
1148 lb naphtha 9.7 million Btu fuel 58 kWhr power 1600 lb feed water 12,700 gal cooling water	Lurgi Low-Pressure Process	Naphtha is converted with steam to a CO and H_2-rich gas and then converted to methanol in presence of catalyst at 200°-300°C	1 ton methanol	Small amount of higher alcohol is produced	**Sulfur removal is necessary for feedstocks containing sulfur.**
Coal-or Oil Shale-Derived Heavy Fuel Oil to Methanol[18]					
2020 lb Bunker "C" (18,300 Btu/lb) 130 kWhr power 1680 lb feed water 19,800 gal cooling water	Lurgi Low-Pressure Process	Heavy feedstock is converted to synthesis gas by partial oxidation and then converted to methanol in presence of catalyst at 200°-300°C	1 ton methanol	Small amount of higher alcohol is produced	**Sulfur removal problems are similar to coal gasification problems.**

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Table 5-5. PROCESSES FOR AMMONIA PRODUCTION

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
Coal to Ammonia					
1.8 ton coal 147 kWhr 6600 lb boiler feed water 490,000 cooling water	Make H_2 by any process, then make ammonia	Requires 44.05 million Btu/ton NH_3	1 ton of ammonia	Depends on gasification process.	Sulfur removal problems are similar to coal gasification problems.
Coal-or Oil Shale-Derived Light Naphtha to Ammonia[25]					
0.81 tons naphtha 33.5 kWhr 6180 lb boiler feed water 468,000 lb cooling water	Gasify naphtha to produce H_2 and then make ammonia	Requires 33.7 million Btu/ton NH_3	1 ton of ammonia	--	Sulfur removal is necessary for feedstocks containing sulfur
SNG to Ammonia[38]					
32.6 million Btu of natural gas as feed and fuel. 15 kWhr 22,400 lb make-up water	Reform natural gas to make H_2 and then make ammonia	Requires about 32.9 million Btu/ton of NH_3	1 ton of ammonia	--	Minimum pollution problems.
Coal-or Oil Shale-Derived Heavy Oil to Ammonia[25]					
0.94 tons Bunker "C" oil 110 kWhr 3840 lb boiler feed water 883,000 lb cooling water	Gasify to produce H_2 and then make NH_3	Requires about 36.9 million Btu/ton of NH_3	1 ton of ammonia	--	Sulfur removal problems are similar to coal gasification problems.

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Table 5-6. PROCESSES FOR HYDROGEN PRODUCTION

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
Coal to Hydrogen[12]					
32 tons coal (12,300 Btu/lb) 2000 kWhr power 64,000 gal water	Gasify coal by any gasification process, then shift the produced gas.	Coal is gasified with steam and oxygen, then shifted to produce H_2. The operating conditions of gasifier are 450 psig and 2200°F	1 million SCF H_2 (97% pure)	steam	Sulfur removal problems are similar to coal gasification problems.
19.52 tons coal (12,300 Btu/lb) 2000 kWhr power 24,000 gal water	Process investigated by Bureau of Mines	Coal reacts with steam and the heat of reaction is supplied by a helium stream cycling between a nuclear heater and the gasification system	1 million SCF H_2 (98% pure)	steam	Sulfur removal problems are similar to coal gasification problems.
SNG to Hydrogen[37]					
246 million Btu feed; 166 million Btu fuel; 1040 kWhr power; 133,00 gal cooling water 9300 gal boiler feed water	Steam Methane Reforming	Reforming pressure is about 290 psig	1 million SCF H_2 (98% pure)	34,200 lb steam	Minimum pollution problems.

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Table 5-6, Cont. PROCESSES FOR HYDROGEN PRODUCTION

Energy/Material Resources	Name of the Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
Coal- or Oil Shale-Derived Naphtha to Hydrogen[32]					
13,000 lb naphtha feed; 7600 lb naphtha fuel 1160 kWhr power 188,700 gal cooling water 6050 gal boiler feed water	Steam-Naphtha Reforming	Reforming pressure is about 290 psig	1 million SCF H_2 (98 % pure)	5,020 lb steam	Sulfur removal is necessary for feedstocks containing sulfur.
Electrical Energy to Hydrogen[32]					
559 lb of distilled water; 140,000 kWhr AC or 130,000 kWhr DC 290,000 gal cooling water (1 kWhr = 3413 Btu)	Electrolytic Process	Hydrogen is generated on the cathodes and oxygen on the anodes by electrolysis of distillated water. The operating conditions are 160°F and about atmospheric pressure.	1 million SCF H_2 (99.9 % pure)	0.5 million SCF O_2 (99.7 % pure)	Minimum pollution problems.

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in the Lurgi Process, the sulfur is removed from the raw material and products by gasifying it to sulfur dioxide and hydrogen sulfide. Then the elemental sulfur is recovered from sulfur dioxide and hydrogen sulfide by one of the many available processes (e.g., Claus Process, Stretford Process). Comments on pollution for many of these processes are included in Tables 5-1 through 5-6.

Appendix B contains a detailed description of (and economic estimates for) the production of gasoline, distillate oils, methanol, and SNG from coal by several example (pattern) processes for which there are sufficient data for characterization.

5.2 Fuel Synthesis From Oil Shale

Many processes produce gaseous or liquid fuels from oil shale. Some processes are on the pilot-plant scale (e.g., Tosco-II Process, Gas Combustion Retort Process, Union Oil Process), and some are in commercial use (e.g., Petrosix Process, GCOS* Process). As shown in Figure 5-2, oil shale can be hydrogasified to gaseous fuel, or it can be retorted to make liquid fuel. The liquid fuel then can be gasified to produce gaseous fuels. Table 5-7 lists some of the processes for making fuels from oil shale.

The processed (spent) shale is a fine, granular, dark residue — dark due to residual carbon that coats the particles because the low temperatures in the processing retort do not produce any significant agglomeration into clinkers. More than 75% (by weight) of feed shale becomes spent shale. Therefore, disposition of spent oil shale is a major problem, and once this shale has been deposited, there remains the problem of revegetating the deposit. Studies are being conducted to resolve this problem.

Appendix B presents a detailed description of (and economic estimates for) the production of gasoline and distillate oils from oil shale by a selected (pattern) process for which there are sufficient data for characterization. The processing of oil shale for liquid hydrocarbons results in a heavy "syncrude" oil, and petroleum-refining techniques are required for finishing. Table 5-8 presents the usual products from the refining of crude oil and the energy requirements.

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* Great Canadian Oil Sands, Ltd.

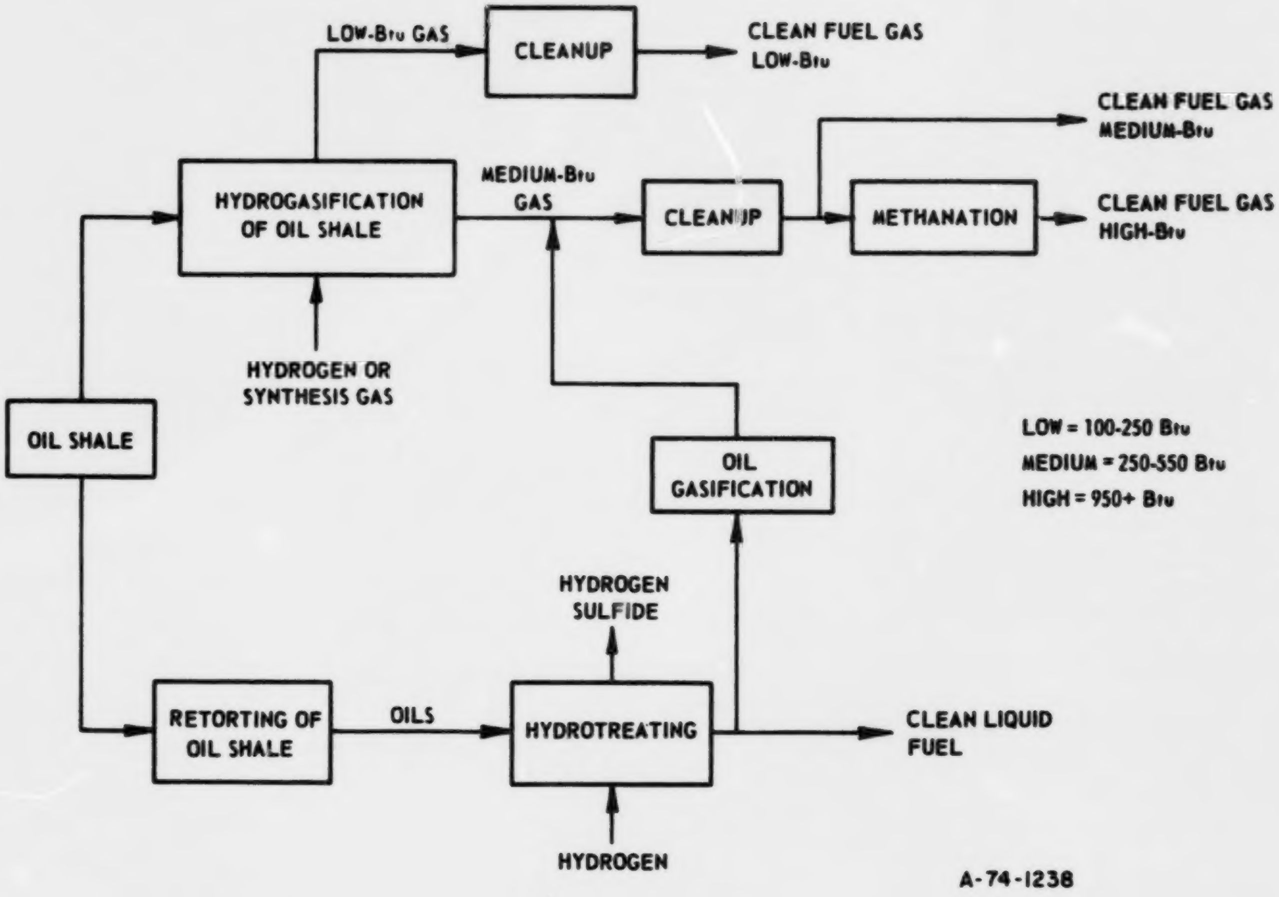

LOW-Btu GAS
CLEANUP
CLEAN FUEL GAS
LOW-Btu
CLEAN FUEL GAS
MEDIUM-Btu
HYDROGASIFICATION
OF OIL SHALE
MEDIUM-Btu
GAS
CLEANUP
METHANATION
CLEAN FUEL GAS
HIGH-Btu
HYDROGEN OR
SYNTHESIS GAS
OIL SHALE
OIL
GASIFICATION
LOW = 100-250 Btu
MEDIUM = 250-550 Btu
HIGH = 950+ Btu
HYDROGEN
SULFIDE
RETORTING OF
OIL SHALE
OILS
HYDROTREATING
CLEAN LIQUID
FUEL
HYDROGEN
A-74-1238

Figure 5-2. PRODUCTION OF CLEAN FUELS FROM OIL SHALE

Table 5-7. PROCESSES FOR PRODUCING FUELS FROM OIL SHALE

Energy/Material Resources	Name of Process	Comment on the Process	Synthesized Fuel	By-Product	Comments on Pollution
Oil Shale to Gas[9]					
23,436 tons shale (40 gal/ton Colorado oil shale, 3400 Btu/lb), 14.5 million lb h-p steam (include power required for oxygen plant)	Oil Shale Hydrogasification With Synthesis Gas	Shale is preheated to 300°F by countercurrent exchange with 700°F flue gas. The preheated shale is fed to the hydrogasifier through lock hoppers. The operating conditions are 1000 psig and 1400°F. Synthesis gas is fed to the hydrogasifier.	97.8 million SCF (924 Btu/SCF)	38.9 tons benzene 63.3 tons carbon from partial oxidation. 18,000 tons spent shale. 262.8 tons liquid fuels.	Problem of disposing of large amount of "dirty" spent shale. Sulfur has to be removed from gas streams and liquid products.
24,867 tons shale (36 gal/ton Colorado oil shale, 3200 Btu/lb); 13.4 million lb h-p steam; 10.7 million lb LP steam (Include power required for oxygen plant)	Oil Shale Hydrogasification With Hydrogen	Same as above except hydrogen is fed to the hydrogasifier instead of synthesis gas.	96.5 million SCF (932 Btu/SCF)	51.3 tons benzene 45.1 tons carbon from partial oxidation. 18,400 tons spent shale. 18,400 tons spent shale; 349.4 tons liquid fuels.	Same as above.
Oil Shale to Shale Oil[16]					
66,000 tons shale (36 gal/ton), plus electricity, fuel gas, etc.	TOSCO II Process	The shale is preheated to 500°F by flue gas from ball heater. The heated balls and preheated shale are fed to the retort where shale is pyrolyzed at 900°F. By-product gas is used for firing the ball heater after purification.	59,500 bbl	180 tons NH_3 630 tons coke spent shale	Same as above.

B-94-1730

Table 5-8. PETROLEUM PRODUCTS FROM AND FUEL CONSUMED IN U.S. REFINERIES

		1968[d]	1967	1966	1960	1950	1925[e]
		vol %					
Crude Oil[a] to –	Gasoline	44.7	44.8	45.3	45.2	43.0	32.0
	Kerosene	7.7	7.3	6.5	4.6	5.6	8.0
	Gas Oil and Distillate	22.1	22.2	22.5	22.4	19.0	48.7
	Residual Fuel Oil	7.3	7.6	7.6	11.2	20.2	--
	Lubricating Oils	1.7	1.8	1.9	2.0	2.5	4.2
	Other Products[b]	16.5	16.3	16.2	14.6	9.7	7.1
		100.0	100.0	100.0	100.0	100.0	100.0
		input Btu/bbl crude oil					
	Fuel	698,000	692,000	701,000	744,000	658,000	829,000
	Electric Power[c]	58,100	56,500	49,200	47,000	22,900	--
	Steam[c]	6,500	7,200	6,200	6,700	--	--
	Total	762,600	755,700	756,400	797,700	680,900	829,000
	Average Thermal Efficiency	87.43%	87.54%	87.51%	86.82%	88.69%	86.18%

[a] 1 bbl of crude oil = 6 million Btu.

[b] Other products include fuel.

[c] 1 kWhr(e) generated corresponds to 13,400 Btu (heat) and 1 lb steam requires 1100 Btu.

[d] Preliminary.

[e] Residual fuel oil included with gas and distillates.

B-94-1718

5.3 Fuel Synthesis From Nuclear Energy

The 40 nuclear power plants now in operation in the U.S. produce about 1% of the nation's energy, but this is projected (optimistically) to soar to more than 45% by the year 2000. Nuclear fission of uranium or other fissile fuels produces heat, and this generated heat is utilized to produce steam for turbines and ultimately electricity. Three types of reactor systems have been commercialized in the U.S.:

- Light-water reactors (LWR)
  - a. Pressure-water reactor (PWR)
  - b. Boiling-water reactor (BWR)
- High-Temperature Gas-Cooled Reactor (HTGR).

Two others are in the development stage:

- Breeder reactors
  - a. Steam-cooled breeder reactor (SBR)
  - b. Light-water breeder reactor (LWBR)
  - c. Molten-salt breeder reactor (MSBR)
- Fast breeder reactors
  - a. Liquid-metal fast breeder reactor (LMFBR)
  - b. Gas-cooled fast breeder reactor (GCFBR)
- Heavy-water-moderated organic-cooled reactor (HWOCR) (low-priority project).

Figure 5-3 is a diagram of a nuclear fuel cycle for an LWR.[7]

The potential efficiency of a conventional nuclear electric conversion plant is on the order of 33%, according to the AEC,[2] though in practice, commercial plants have not achieved this high a figure. The HTGR is intended to operate at an efficiency nearer to 40%.

At present, the commercial practice for extracting energy from these reactors is as electric power. The power generation cycle involves steam or possibly helium gas turbines. However, the electric power can be used to produce a chemical fuel. Hydrogen can be produced by electrolysis from water by using commercially available electrolyzers, and this hydrogen can be used as a fuel or as a feedstock for the manufacture of another fuel, such as ammonia or a hydrocarbon.

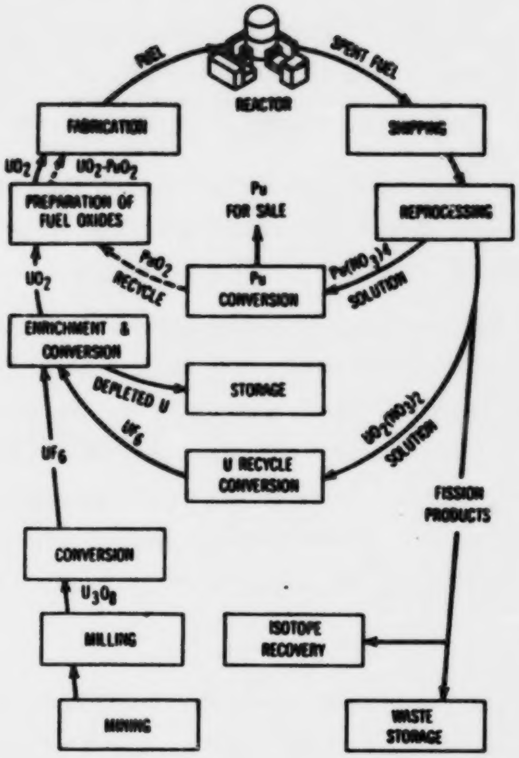

FUEL
SPENT FUEL
REACTOR
FABRICATION
SHIPPING
UO_2
UO_2-PuO_2
PREPARATION OF FUEL OXIDES
Pu FOR SALE
REPROCESSING
PuO_2 RECYCLE
Pu CONVERSION
$Pu(NO_3)_4$ SOLUTION
UO_2
ENRICHMENT & CONVERSION
DEPLETED U
STORAGE
UF_6
$UO_2(NO_3)_2$ SOLUTION
U RECYCLE CONVERSION
UF_6
FISSION PRODUCTS
CONVERSION
U_3O_8
MILLING
ISOTOPE RECOVERY
MINING
WASTE STORAGE

Figure 5-3. NUCLEAR FUEL CYCLE FOR LIGHT WATER REACTOR (Source: Ref. 7)

Recently, attention has been given to the possibility of the use of process heat directly from the core of a HTGR or GCFBR to drive a chemical process. The production of hydrogen by this means is a distinct possibility.

Thermal decomposition of water is a concept that merits technology development. Because of the temperature limitations of nuclear reactors and conventional process equipment, direct single-step water decomposition cannot be achieved, but a sequential chemical reaction series can be devised in which hydrogen and oxygen are produced, water is consumed, and all other chemical products are recycled. This multistep thermochemical method offers the potential for processes that can use high-temperature nuclear heat and be contained in chemical process equipment.

An example of such a chemical reaction sequence is as follows[28]:

$$\begin{array}{l} 2CrCl_2 + 2HCl \rightarrow 2CrCl_3 + H_2 \\ 2CrCl_3 \rightarrow 2CrCl_2 + Cl_2 \\ H_2O + Cl_2 \rightarrow 2HCl + 1/2O_2 \\ \hline H_2O \rightarrow H_2 + 1/2O_2 \end{array}$$

A thermochemical hydrogen production plant that directly uses the heat from a nuclear reactor might be more efficient (depending on the chemical process) than a nuclear electric generator-water electrolyzer plant.

Thermochemical hydrogen production offers a closed-cycle, non-material-polluting route to gaseous fuel synthesis. It would be environmentally compatible because there would be no by-products (except oxygen), and combustion of the produced hydrogen recreates the raw material, water. In the longer term, thermochemical hydrogen production offers a conversion technology for transforming heat from any high-temperature source into chemical energy by using a perpetually available material resource.

One of the prospects for nuclear process heat that has been investigated by General Atomic Co. is the production of gaseous fuels from coal.[19] The conversion of carbon and steam to hydrogen and carbon monoxide is exothermic (evolves heat), but the shift of the carbon monoxide with steam to produce more hydrogen is endothermic (requires heat). The overall carbon-to-methane process also is endothermic. These reactions are as follows:

$$C + H_2O = CO + H_2 \text{ evolves 28 kcal/mol}$$

$$CO + H_2O = CO_2 + H_2 \text{ requires 10 kcal/mol}$$

$$C + 2H_2 = CH_4 \text{ requires 20 kcal/mol}$$

Figure 5-4 is a simplified diagram of the process being developed by Stone and Webster Inc. and General Atomic Co. The coal is ground, mixed with a coal-derived solvent, and solubilized in the presence of hydrogen. The liquid coal is further hydrogenated in subsequent steps, the final product being primarily a high-Btu gas with some low-sulfur aromatic liquids. A portion of the gas is cycled to the steam-methane reformer located in the nuclear reactor vessel, where the endothermic steam-methane reforming takes place. The resulting hydrogen-rich gas

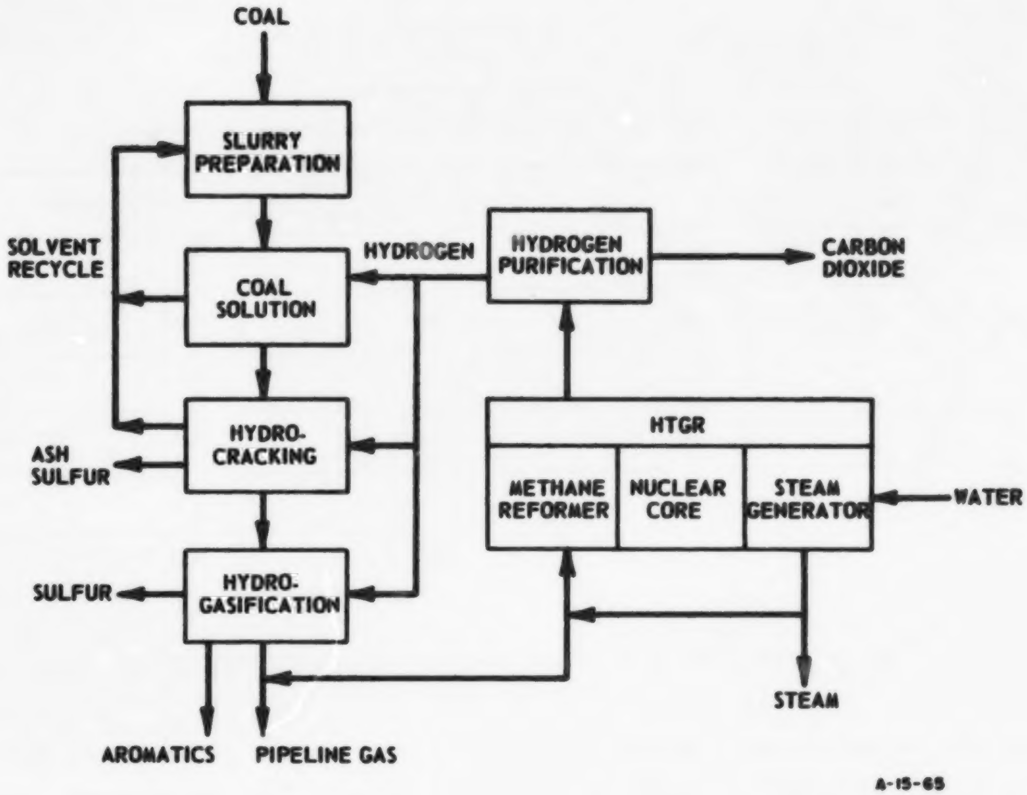
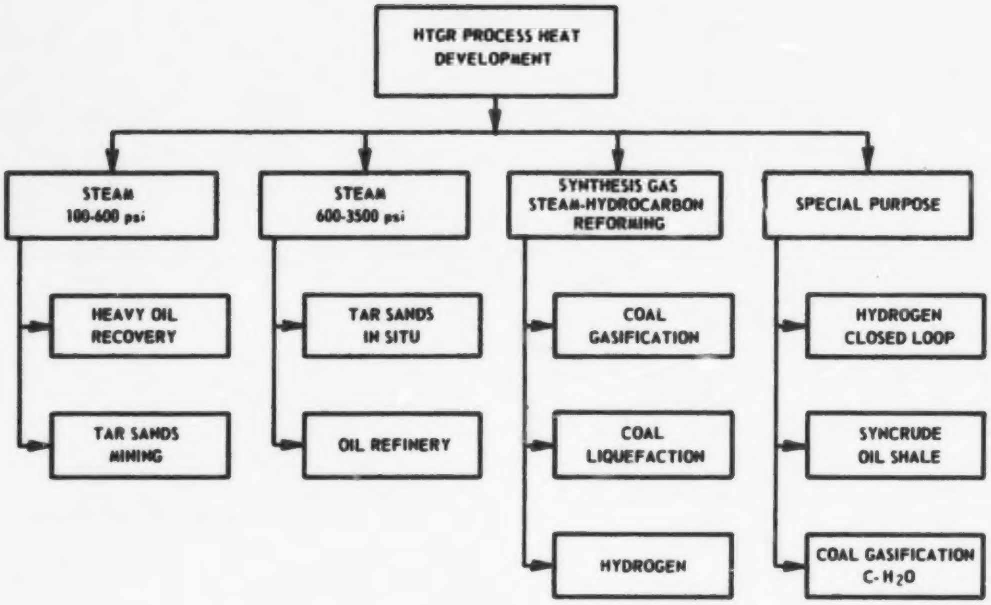

COAL
SLURRY PREPARATION
SOLVENT RECYCLE
COAL SOLUTION
HYDROGEN
HYDROGEN PURIFICATION
CARBON DIOXIDE
HYDRO-CRACKING
ASH SULFUR
HTGR
METHANE REFORMER
NUCLEAR CORE
STEAM GENERATOR
WATER
SULFUR
HYDRO-GASIFICATION
STEAM
AROMATICS
PIPELINE GAS
A-15-65

Figure 5-4. COAL GASIFICATION PROCESS BEING DEVELOPED BY STONE AND WEBSTER AND GENERAL ATOMIC (Source: Ref. 29)

is taken to the carbon monoxide-shift and carbon dioxide-stripping sections before compression and entry into the coal-processing sequence. The HTGR also provides high-pressure steam to drive the hydrogen compressors and a turbine-generator set for in-plant electrical needs.

Figure 5-5 shows some general applications of HTGR heat that are possible (in concept) for the production of fuels.

As with other techniques of energy conversion and fuel production, nuclear processes do pollute the environment.[36,40] The overall thermal conversion efficiency of a nuclear power plant (Table 5-9) is about 30%, compared with perhaps 40% in conventional plants. Moreover, none of the inefficiency or waste heat is discharged through a stack, which accounts for a considerable part of the heat dissipation from a conversion


HTGR PROCESS HEAT DEVELOPMENT
STEAM 100-600 psi
STEAM 600-3500 psi
SYNTHESIS GAS STEAM-HYDROCARBON REFORMING
SPECIAL PURPOSE
HEAVY OIL RECOVERY
TAR SANDS MINING
TAR SANDS IN SITU
OIL REFINERY
COAL GASIFICATION
COAL LIQUEFACTION
HYDROGEN
HYDROGEN CLOSED LOOP
SYNCRUDE OIL SHALE
COAL GASIFICATION C-H_2O

A-74-1239

Figure 5-5. HTGR APPLICATIONS TO FUEL PRODUCTION
(Source: Ref. 30)

plant. Consequently, a large amount of heat (twice as much as for a conventional plant) is discharged to rivers or to the atmosphere, causing thermal effects that may be hazardous to plant and animal life. In commercial use, fuel rods have, on infrequent occasions, developed some leaks, allowing fission product leakage into the primary cooling water. This represents a potential for serious environmental contamination with radioactivity and must be taken into consideration in the plant design.

Some radioisotopes produced in the nuclear-fuel-reprocessing cycles have very short lives, others last for days, and a few remain radioactive for thousands of years. At present, the high-activity radioactive liquid wastes are delivered to underground storage tanks for long-term containment and decay, causing serious concern over their ultimate disposal.

Table 5-9. CHARACTERISTICS OF NUCLEAR MODEL PLANTS[a] (Source: Ref. 2)

	Boiling Water		Pressurized Water	
Plant starting commercial operation in period:	1976-80	1981-85	1976-80	1981-85
Thermal efficiency (%)	34	34	33	33
Specific power (MWt/MTU)	22	26	37	41
Initial Core (average)				
Irradiation level (MWDt/MTU)	21,000	24,000	26,000	26,000
Fresh fuel assay (wt.% U-235)	2.2	2.4	2.8	2.7
Spent fuel assay (wt.% U-235)	0.8	0.7	0.9	0.8
Fissile Pu discharged (kg/MTU)	5.1	5.4	6.0	6.0
Feed required (ton U_3O_8/MWe)[b]	0.680	0.635	0.545	0.480
Separative work required (kg/MWe)[b]	345	340	320	275
Replacement Loadings (steady state)				
Irradiation level (MWDt/MTU)	27,000	33,000	33,000	33,000
Fresh fuel assay (wt.% U-235)	2.6	2.8	3.3	3.2
Spent fuel assay (wt.% U-235)	0.8	0.7	0.9	0.8
Fissile Pu discharged (kg/MTU)	5.6	5.9	6.7	6.7
Feed required (ton U_3O_8/MWe/yr)[b]	0.145	0.140	0.165	0.165
Separative work required (kg/MWe/yr)[b]	105	100	130	125

[a] MWt is thermal megawatts, MWe is electrical megawatts, MWDt is thermal megawatt days, MTU is metric tons (thousands of kilograms) of uranium, and ton U_3O_8 is short tons (2,000 pounds each) of yellowcake from a refinery. Separative work is given in kilogram units.

[b] Based on operation of enriching facilities at a tails assay of 0.2% U-235 and on no recycle of plutonium. For replacement loadings the required feed and separative work are net, in that they allow for the use of uranium recovered from spent fuel.

5.4 Fuel Synthesis From Solar-Agricultural Sources and Waste Materials

Solar energy is the most abundant form of energy available on the earth, but it is very diffuse at the earth's surface. As a result, it is expensive to capture the large amounts of energy required for conversion and distribution at commercial levels because of the large surface areas required for "collection" of the solar energy.

5.4.1 Solar Energy to Electricity

Many ways are being developed for converting solar energy to electricity, such as solar thermal conversion, photovoltaic conversion, ocean thermal difference, wind power, and bioconversion. Solar energy systems have no fuel cost, but they currently require higher initial capital investments than other energy systems.

Drs. Aden B. and Marjorie Meinel have proposed that solar radiation might be captured so efficiently that the overall conversion to electricity by means of a thermal (steam) cycle would be 25-30% efficient.[17] Here, solar energy is converted to thermal energy and generated heat is utilized to produce steam for turbines to produce electricity. A material such as liquid sodium is used as a heat-transport fluid operating at about 1000°F and is pumped through steel conduits throughout the solar-energy-collecting field. The high-energy radiation from the sun is absorbed as heat by a semiconductor layer, and the heat flows by conduction to the liquid sodium. According to the Meinels' estimates, about 8 square kilometers of collecting surface and a 50-million-liter thermal storage tank would be required for the equivalent of a 1000-MW generating plant. Based on 10,000 Btu/kWhr, a heat input of 10 billion Btu/hr would be required for a 1000-MW plant.

Photovoltaic conversion is another means of producing electricity from solar energy. This is based on the utilization of the photovoltaic effect in solid-state devices, in which the absorption of light generates free electrical charges, which can be collected on contacts applied to the surface of semiconductors. The theoretical thermal efficiency is about 24% at room temperature. An orbiting-satellite collector system has been proposed by Dr. Glaser.[13] This scheme proposes the positioning of two geo-stationary satellites such that one is illuminated by the sun at all times. Both would have a direct line of sight to the same point on earth. According to Dr. Glaser, to produce 0.5 trillion kWhr of electrical energy, an orbiting solar collector with a conversion efficiency of 100% would need an area of 16 square miles for this energy. This corresponds to approximately 105 square miles of silicon cells weighing 180 million pounds, with an assumed efficiency of about 15%.

Electric energy can be generated from ocean temperature differences. More than 70% of the solar radiation falls on the ocean, which creates a pronounced temperature difference between the surface and lower layers of the ocean. The hot water at the top would provide heat to boil another working fluid (such as ammonia or propane). The produced vapor would expand through a turbine to produce electricity. The bottom cool water would provide cooling to condense the vapor back to liquid. The average temperature difference between surface and lower layers is about 18°F in selected parts of the ocean, which would yield an efficiency of about 4%.[27] The transfer of electric power from ocean to the shore is also a capital-consuming step.

Wind energy is an indirect form of solar energy. The use of wind power to drive a propeller to produce electrical energy is not new.

Solar energy can be utilized in the bioconversion of organic matter. Algae have the capability of converting visible light energy into cellular energy under a wide range of conditions. This cellular energy is transformed into the chemical energy of methane and other combustible gases by anaerobic digestion. Methane thus formed would be burned in a gas turbine generator system to produce electricity.[14] The overall efficiency of the process is less than 4%.[34]

5.4.2 Solar Energy to Agricultural Products

A solar plantation is another way of utilizing solar energy. The energy from a plantation is a perpetually renewable source of fuel.

No one has tried to grow forests or other crops purposely for fuel on a large scale in the U.S. Wood charcoal is produced in several parts of the country, but the wood used is a scrub growth or wood waste. However, data that are available can be used to estimate fuel values potentially available from forest and farm crops; fuel value production and estimated efficiencies of conversion of solar energy to vegetable matter are given in Table 5-10.

Table 5-10. FUEL VALUE PRODUCTION AND ESTIMATED EFFICIENCIES OF CONVERSION OF SOLAR ENERGY TO VEGETABLE MATTER (Source: Ref. 33)*

Plant	Age of plant (years)	Location	Yield (tons/acre-year) o.d. or a.d.[a]	Fuel value assumed (Btu/lb)	Estimated solar energy conversion[b] (%)	Reference
Alfalfa:						
U.S. average, 1969	1−	U.S.	2.85 o.d.	6500		(*1*)
2 cuttings per season	1−	U.S. Midwest	3.60 o.d.	6500		(2)
3 cuttings per season	1−	U.S. Midwest	4.60 o.d.	6500	0.29	(2)
Reed Canary Grass	1−	U.S. Midwest	6.32 o.d.	6500	0.39	(3)
Corn:						
mature silage	1−	U.S. Midwest	8.50 o.d.	6500	0.41	(*4*)
stalk and ears	1−	U.S.	7–11 o.d.	6500	0.44–0.69	(*5*)
Gen. Agriculture	1−	U.S.	4.5–13.5 o.d.	6500	0.28–0.85	(*5*)
Sugar Cane	?	La. and Fla.	20 o.d.	6500	1.2	(*5, 6*)
Cottonwood	2	Ala. and Miss.	2.0 a.d.	5800		(*7*)
Cottonwood	7	Ala. and Miss.	3.1 a.d.	5800		(*8*)
Slash Pine (crown & bole)	20+	Southeastern States, U.S.	3.8–4.8 a.d.	7000	0.24–0.30	(*9*)
Conifers:						
Pseudotsuga toxifolia[c] *Pinus Nigra*[d] *Picea abies*[e]	18–22	England, lat. 51°–52° North			0.37	(*10*)
Sycamore	5	Georgia	1.6–11.2 a.d.	5800	0.64	(*11*)

[a] o.d. = oven dry; a.d. = air dry (12 to 20% moisture content).

[b] Based on annual average insolation equal to 1300 Btu/ft^2-day.

[c] Douglas Fir.

[d] A species of pine.

[e] A species of spruce.

5.4.3 Fuel Synthesis From Biomass and Waste Materials

The use of biomass material, growing plant organisms, or organic waste is a means of obtaining energy from a renewable source. The technology of converting nonfossil, renewable carbon to a synthetic fuel uses two major sources of raw material: 1) growth of plants and 2) collection of organic waste produced by the conversion of solar energy to chemical energy. Thus, the two broad classifications, by resource base, for biomass fuel synthesis are waste products and plant materials. Fuel synthesis from waste products uses the same technology as fuel synthesis from plant materials except that its raw material has to be collected and sorted before the organic material can be used.

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If direct burning is not used to extract the energy from either the waste or plant material, four general processing methods — pyrolysis, hydrogasification, anaerobic digestion, and (aerobic) fermentation — can be used to convert the raw material to low-Btu gas, SNG, liquid fuel, or any combination of these fuels. Each method is reviewed, and some of the advantages and disadvantages of each technique are emphasized.

5.4.3.1 Pyrolysis

Pyrolysis involves the thermal decomposition of organic matter at about atmospheric pressure and at temperatures generally above 1000°F in the absence of oxygen to produce a complex mixture of gaseous, liquid, and solid products. A typical distribution of products reported by the U.S. Bureau of Mines for the pyrolysis of raw municipal refuse at 1650°F is given in Table 5-11. Chemically, the process results in fragmentation and rearrangement of the more complex organic molecules in the waste to yield simpler molecules.

Table 5-11. PRODUCTS OF PYROLYSIS OF MUNICIPAL WASTE (Source: Ref. 31)

	Yield per Ton of Feed
Gas	17,741 SCF
Oil	0.5 gal
Ammonium sulfate	25.1 lb
Aqueous	113.9 gal
Residue	154 lb

One major disadvantage of pyrolysis is that, although the product gas contains appreciable amounts of methane, the product distribution is usually complex, as shown in Table 5-11. The gas has a heating value of about 450 Btu/SCF and contains methane (12.7 mole percent), hydrogen (51.9 mole percent), carbon monoxide (18.1 mole percent), carbon dioxide (11.4 mole percent), and 5.2 mole percent C_2 and higher components. Light oil, ammonium sulfate, an aqueous phase containing water-soluble organics, and a residue that contains mainly a lightweight flaky char and the nonorganics also are produced. The char has a heating value of about 5300 Btu/lb.

Several groups currently are developing pyrolysis processes for the production of fuel gas from organic wastes; among them are Battelle Memorial Institute, Union Carbide Corp., Hercules Inc., Monsanto Co., and Occidental Petroleum Corp. A process using a fluidized-bed system is being developed at West Virginia University.[39] Described as an example, the heart of this process is depicted in Figure 5-6.

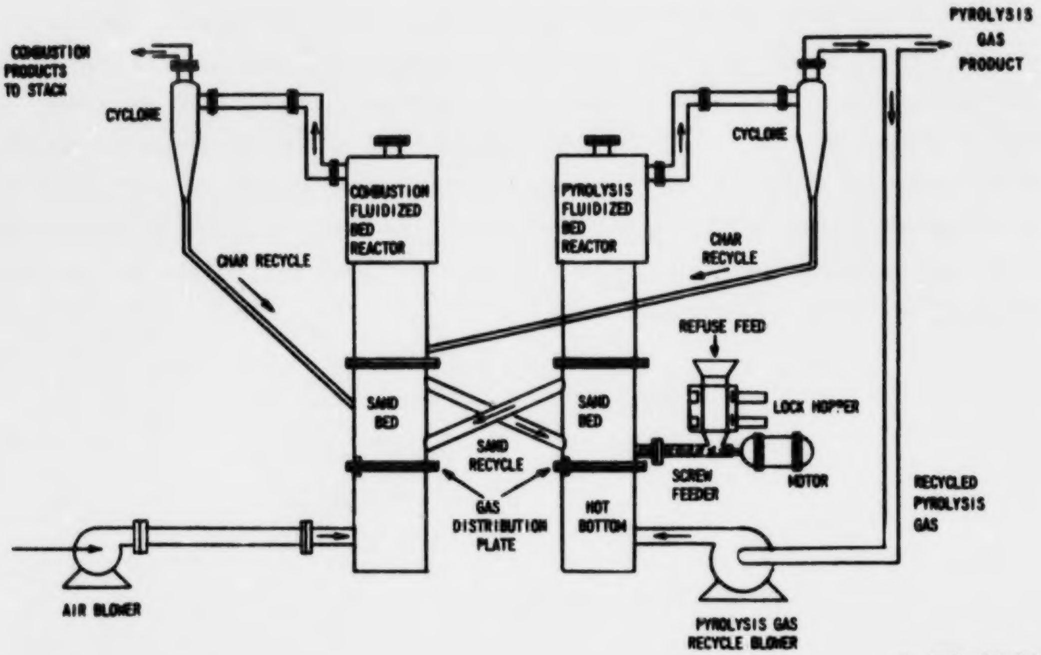
COMBUSTION PRODUCTS TO STACK
CYCLONE
COMBUSTION FLUIDIZED BED REACTOR
PYROLYSIS FLUIDIZED BED REACTOR
CYCLONE
PYROLYSIS GAS PRODUCT
CHAR RECYCLE
CHAR RECYCLE
REFUSE FEED
LOCK HOPPER
SAND BED
SAND BED
SAND RECYCLE
SCREW FEEDER
MOTOR
RECYCLED PYROLYSIS GAS
GAS DISTRIBUTION PLATE
HOT BOTTOM
AIR BLOWER
PYROLYSIS GAS RECYCLE BLOWER

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Figure 5-6. SCHEMATIC DIAGRAM OF THE MUNICIPAL REFUSE PYROLYSIS PROCESS WITH FLUIDIZED SAND RECYCLE AND CHAR RECYCLE (Source: Ref. 39)

In this design, the heat given off by combustion of the char supplies the energy for pyrolysis. The oxygen required for combustion is supplied by compressed air. To prevent nitrogen from diluting the gas, pyrolysis and combustion are conducted in separate reactors, each of which contains equal depths of fluidized sand. Energy transfer is accomplished by sand flow from the combustion reactor at 1750°F to the pyrolysis reactor at 1500°F. The feed to the pyrolysis unit is municipal refuse, whereas that to the combustion unit is char. Subsequent processing of the pyrolysis gas by shifting, scrubbing, and methanation yields SNG. The projected compositions of the product gas after each treatment step are summarized in Table 5-12.

Table 5-12. PYROLYSIS GAS PRODUCED FROM 400 TONS/DAY OF MUNICIPAL REFUSE[a] (Source: Ref. 39)

Component	Pyrolyzer Exit	CO-Shift Exit	CO_2 Scrubber Exit	Methanator Exit
	1000 SCF/day (dry basis)			
Carbon Dioxide	785	1610	--	--
Carbon Monoxide	1700	870	870	--
Methane	530	530	2610	1400
Hydrogen	1780	2610	2610	--
Total	4795	5620	4010	1400

[a] Refuse feed contains, on the average, 30% moisture.

The SNG yield from this process corresponds to about 2.5 SCF of methane per pound of feed, or an overall thermal efficiency of about 35% in terms of the energy content of the dry feed and the SNG.

If pyrolysis is viewed as strictly a disposal process, its costs appear to be competitive with those for incineration, which generally range from about \$3 to \$10/ton. However, as an SNG-producing process, the added costs of the other unit operations needed to produce pipeline-quality (high-Btu) gas would appear to make the total costs too high. Low-Btu-gas applications are probably more suitable for such processes.

In the next few years, several processes are scheduled for demonstration on a scale of 50-100 tons/day of waste feed.

Pyrolysis also can be used to convert solid waste into a liquid fuel. The conversion of organic waste into a liquid fuel has the advantage that the material can be more easily stored or tanked than gaseous alternatives. Two processes are currently under development, one by the Bureau of Mines and one by Garrett Research Corp. The Garrett process has received EPA and City of San Diego support and a demonstration plant is under way in San Diego.[24]

The first phase of the Garrett system consists of a crusher, metals, and glass separater, and dryer. This prepares the waste for the converter. In this case, the conversion process is pyrolysis, and it occurs in a reacting system of proprietary design. The pyrolysis is fast, and the temperature is about 800°F. The liquid product is purported to be a replacement for No. 6 fuel oil, and the heating value of this oil is 12,000 Btu/lb.

The Bureau of Mines has reported on the batch heating of waste in a hydrogen atmosphere. The temperature is 250°-400°C, and the hydrogen pressure is 100-300 atm. The process yields 2 bbl/ton of waste.

5.4.3.2 Hydrogasification

A limited amount of work has been done on the hydrogasification of municipal waste. Limited proprietary studies have been carried out at IGT with paper, the major component of municipal solid waste, and a few experimental studies were reported by Feldmann of the Bureau of Mines.[8] Basically, the concept of waste hydrogasification is based on the premise that any organic material can be treated with hydrogen at elevated temperatures and pressures to produce methane.

Part of the waste feed is used to convert hydrogen to synthesis gas by partial oxidation and shifting, which are followed by hydrogasification and gas purification. For a balanced plant, Feldmann estimates that about 40% of the carbon in the feed can be converted to SNG, while the remaining 60% is used for hydrogen production. This corresponds to a maximum SNG yield of about 3.8 SCF of methane per pound of feed, or an overall maximum thermal efficiency of about 65%, again in terms of the energy content of the SNG and the dry feed. In one preliminary experiment, 53% of the carbon in a typical municipal waste was hydrogasified at about 1025°F and 1300 psig to produce, after methanation, a 936-Btu/SCF gas. Detailed experimental data and process design studies have not been published. However, the reported experimental work indicates that conversion levels high enough to allow balanced operation of the plant can be achieved.

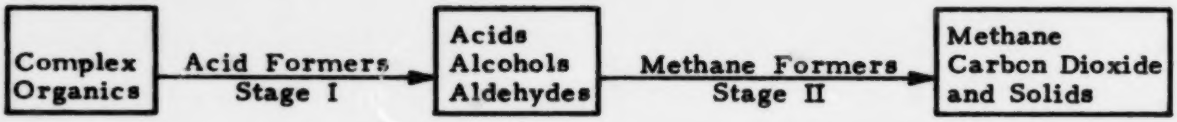
A major problem in pyrolysis or hydrogasification of organic waste to produce SNG is the large amount of water in the raw waste. A large part of the energy content of the waste is needed during pyrolysis and hydrogasification to remove the water. In many cases, little or no net energy can be derived from the overall process in the form of methane.

For example, consider a waste that has a moisture content of 85% and a fuel value of 5000 Btu/dry lb. These values are close to those often encountered in typical agricultural wastes, whereas the moisture content of sludge can be as high as 99%. Heat-drying an 85%-moisture content waste to a final moisture content of 30% or less requires more energy than the fuel value of the waste itself.

5.4.3.3 Anaerobic Digestion

Anaerobic digestion has been known and used for more than 70 years. In simple terms, it consists of the biogasification of organic waste materials by methane-producing bacteria with the concurrent "cleaning" of the waste. The organic substances in the waste are fermented by the organisms. Technically, the process is called anaerobic fermentation, or digestion, because the organisms grow in the absence of oxygen. The process is used throughout the world today, either alone or in combination with other processes, for the treatment of domestic, industrial, and agricultural liquid wastes. However, anaerobic fermentation has not yet been applied to the commercial treatment of solid wastes.

The basic process of anaerobic digestion can be represented as a two-stage process: First, the complex organic materials in the waste are converted to acids, alcohols, and aldehydes by acid-forming bacteria, and then the acids are converted to methane and carbon dioxide by methane-forming bacteria.



Although this is an oversimplification of complicated biological phenomena, the two-stage representation of anaerobic digestion is useful in explaining some of the characteristics of the process, such as the effect of acid buildup and pH.

In general, three types of biodegradable compounds are found in wastes: fats, carbohydrates, and proteins. Fat degradation in anaerobic processes occurs by hydrolysis to fatty acids and alcohols and then oxidation to lower-molecular-weight volatile acids, which are digested. Carbohydrate degradation occurs by molecular disruption to disaccharides and monosaccharides, which then are converted to the lower-molecular-weight components by cell metabolism. Protein degradation occurs by hydrolysis to amino acids and then deamination to the acids. The resulting acids then are converted to methane and carbon dioxide by the methane-formers.

In its conventional design, anaerobic digestion is carried out in a closed tank at the proper fermentation conditions. The entire operation is carried out in a closed unit because oxygen inhibits the digestion process. The escaping gas, containing 50-80% methane and 20-50% carbon dioxide, is collected, and a portion is usually combusted as fuel for the plant to maintain the temperature of the digestion chamber at 85^0-95^0F. At temperatures near 125^0F, the thermophilic microorganisms predominate, and the digestion proceeds at a higher rate.

The production and release of methane stabilize the organic material. The process can be maintained on a large scale for an indefinite period, as long as the usual fermentation parameters are controlled and a continuous supply of waste material is fed to the digester. A schematic drawing of the process in terms of the distribution of components in the digester is shown in Figure 5-7.

The anaerobic digestion process is used in combination with activated sludging in many small, medium, and large cities and towns across the U.S. to treat municipal liquid wastes. The process also is used as the primary treatment for the stabilization and volume reduction of garbage from municipalities and in industry for the treatment of wastes from meat-packing plants. Perhaps the oldest application of anaerobic digestion is the stabilization of organic wastes in septic tanks.

As noted, the problem with pyrolysis and hydrogasification is that large amounts of energy are necessary to separate the carbon and water in the feedstock. Biological gasification by anaerobic digestion overcomes this disadvantage. Anaerobic digestion is applicable to most types of high-moisture-content municipal, agricultural, and industrial organic wastes. Also, in contrast to hydrogasification and pyrolysis, the hardware for large-scale biological digestion is quite advanced.

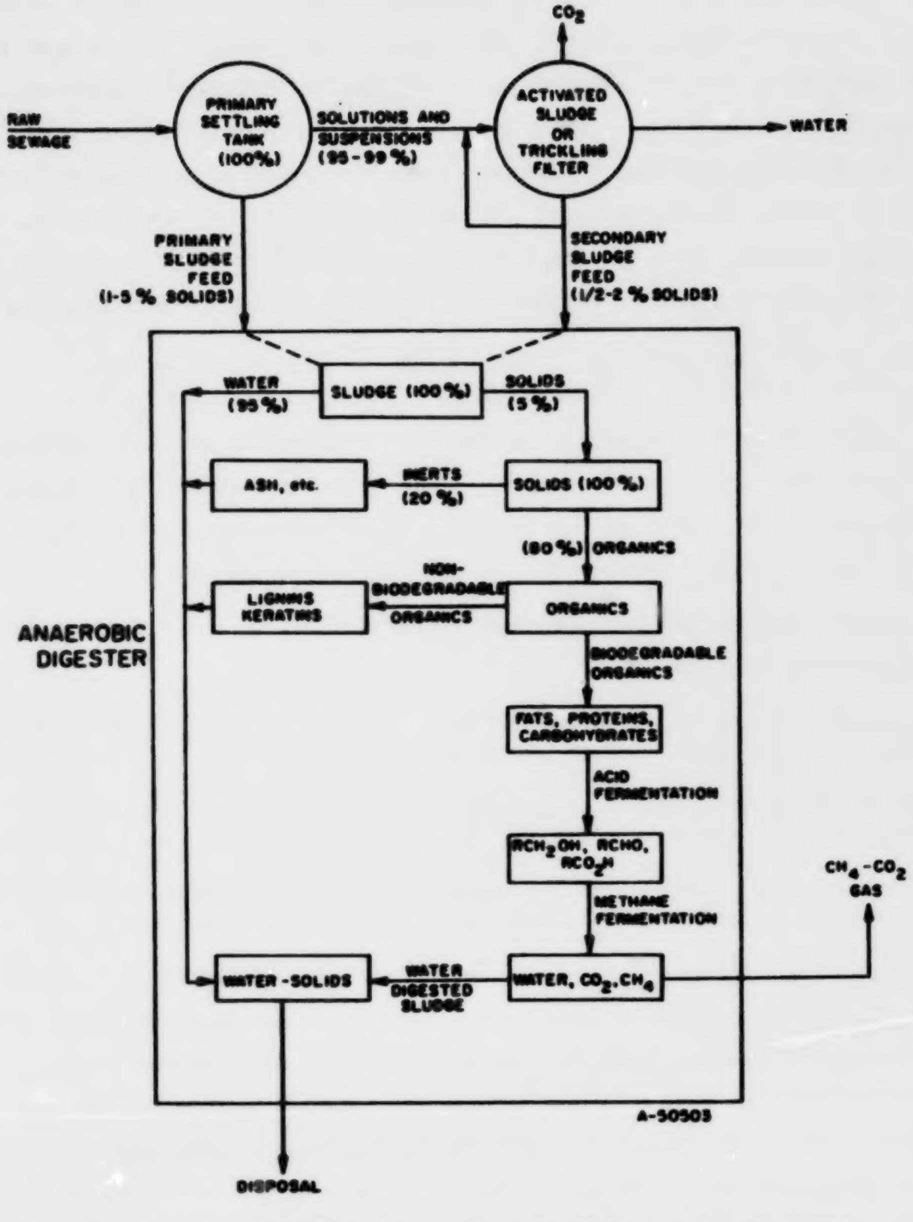

CO2
RAW SEWAGE
PRIMARY SETTLING TANK (100%)
SOLUTIONS AND SUSPENSIONS (95 - 99 %)
ACTIVATED SLUDGE OR TRICKLING FILTER
WATER
PRIMARY SLUDGE FEED (1-5 % SOLIDS)
SECONDARY SLUDGE FEED (1/2-2 % SOLIDS)
WATER (95 %)
SLUDGE (100 %)
SOLIDS (5 %)
ASH, etc.
INERTS (20 %)
SOLIDS (100 %)
(80 %) ORGANICS
NON-BIODEGRADABLE ORGANICS
LIGNINS KERATINS
ORGANICS
ANAEROBIC DIGESTER
BIODEGRADABLE ORGANICS
FATS, PROTEINS, CARBOHYDRATES
ACID FERMENTATION
RCH2OH, RCHO, RCO2H
METHANE FERMENTATION
CH4 - CO2 GAS
WATER - SOLIDS
WATER DIGESTED SLUDGE
WATER, CO2, CH4
A-50503
DISPOSAL

Figure 5-7. SCHEMATIC DRAWING OF ANAEROBIC DIGESTION IN CONVENTIONAL SEWAGE DIGESTER

The major disadvantage of anaerobic digestion is its relatively low gasification rate, compared with the rates of hydrogasification and pyrolysis for the same feeds. Also, in applying anaerobic digestion to the treatment of municipal refuse, special consideration must be given to two factors. Unlike sewage sludge, the organic portion of the refuse is mainly cellulosic and constitutes a nutritionally deficient substrate for the anaerobic organisms. Then too, mixed municipal refuse, as received, cannot be directly gasified because a sizable fraction of this material is oversized, inert, abrasive, and not biodegradable. Consequently, the refuse must be processed, and the inorganic and heavier fractions separated from the organics as much as possible before digestion can begin.

5.4.3.4 Agricultural Products to Alcohol, Fermentation

The main process for the production of ethanol from agricultural products is microbial fermentation. The fermentation is accomplished by enzymatic conversion of fermentable carbohydrates in vegetable matter to ethanol and carbon dioxide by select strains of yeasts.

The main classes of carbohydrate materials that can be used for the purpose are as follows:

a. Saccharine material (containing sugar) such as molasses, sugar beets, fruit juices, sugar cane, corn syrup

b. Starchy materials such as potatoes, cereal grains, cassava, Jerusalem artichokes

c. Cellulosic materials such as wood, agricultural waste such as straw and stocks, and hemicellulose in wood pulp and grasses.

Raw materials of the "a" class are directly fermentable. Those of the "b" class must first be converted to mono- or disaccharides (sugars). This conversion can be brought about 1) by use of mineral acids, 2) enzymatically by use of malt (dried sprouts of barley or rye), amylolytic molds, or bacteria, and 3) by treatment with alpha- and beta-amylase preparations. Those of the "c" class are converted to fermentable carbohydrates by hydrolysis with mineral acids. These fermentable carbohydrates then are yeast-fermented to alcohol. The scheme is shown in Figure 5-8.

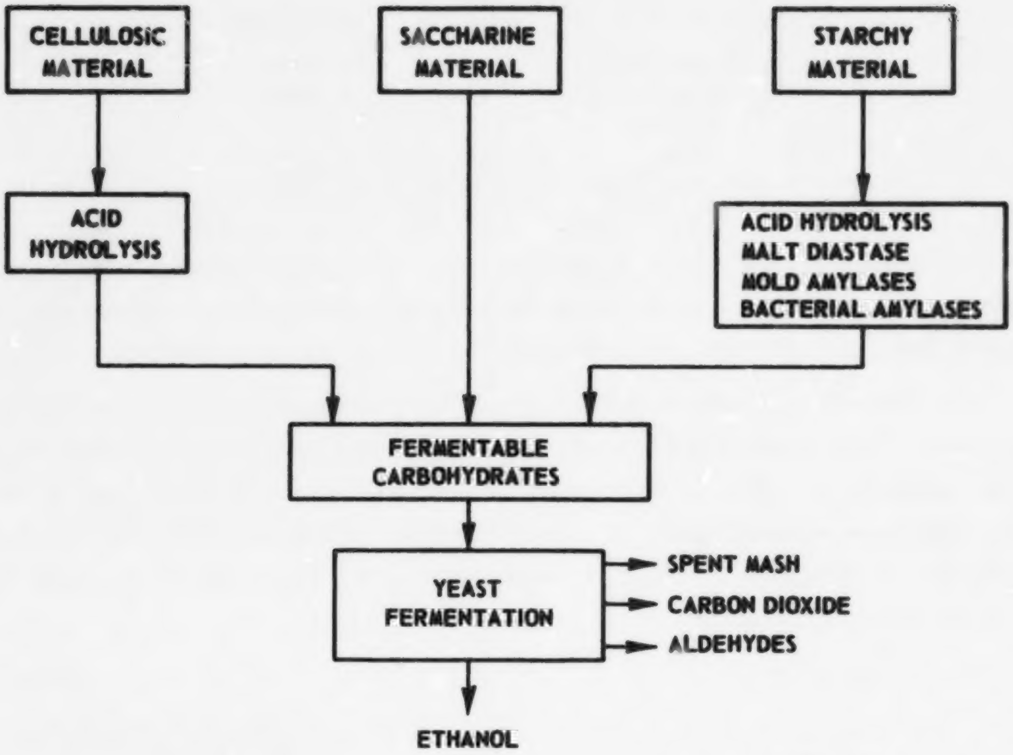

CELLULOSIC MATERIAL
SACCHARINE MATERIAL
STARCHY MATERIAL
ACID HYDROLYSIS
ACID HYDROLYSIS
MALT DIASTASE
MOLD AMYLASES
BACTERIAL AMYLASES
FERMENTABLE CARBOHYDRATES
YEAST FERMENTATION
SPENT MASH
CARBON DIOXIDE
ALDEHYDES
ETHANOL

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Figure 5-8. PRODUCTION OF ETHANOL FROM AGRICULTURAL PRODUCTS

Special strains of yeasts are capable of giving an efficient and rapid conversion. Strains are selected on the basis of alcohol tolerance (up to 12% ethanol by volume is common), efficiency of conversion, speed of fermentation, ability to maintain physiological constancy, and adaptability to harsh conditions (in the case of wood waste).

The amount of the alcohol obtained from a substance is directly proportional to the amount of fermentable sugar that can be produced from that substance. The overall sugar conversion efficiency is 90-99%. From 1 gram of converted sugar, the alcohol yield is 0.51 gram. The remaining 0.49 gram is lost as carbon dioxide.[4]

Ethanol production from some crops is as follows:[3]

	gal/ton	gal/acre
Marigolds	8	150
Artichokes	28	500
Potatoes	22	220
Grain	78	50
Sugar Beet	21	240
Molasses	66	--

A commercial product containing only 95% by volume alcohol can be produced from fermented liquor by straight distillation. However, 99.8% by volume alcohol can be produced by azeotropic distillation.

The main by-products of the alcoholic fermentation of agricultural products are spent mash, carbon dioxide, and aldehydes. After drying, the spent mash can be used as a constituent in cattle feed, or it can be concentrated and used as a core binder in foundries or as a briquet adhesive. Various amounts of fuel oil can be obtained, depending upon the agricultural feed.

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6. FUEL PROPERTIES AND COMPATIBILITY

The subject of fuel properties and compatibility comprises certain chemical and combustion properties, toxicity, transportability and tankage, and compatibility with present-day and futuristic types of engines. Appendix A contains a detailed tabulation of the chemical and combustion properties and the fuel concentrations (in air) that exhibit various degrees of toxicity.

This section presents discussions of fuel transmission, distribution, and tankage on-board a vehicle and then a subjective analysis, based on information in the published literature, of the compatibility of the potential fuels in various types of engines.

6.1 Transmission and Distribution Compatibility

The introduction of an alternative automotive fuel that has properties unsuitable for the equipment now used for energy transmission and distribution would be difficult and expensive. The great economic incentive for retaining existing facilities would have to be overcome. Fuels that can be handled in existing equipment therefore have an enormous advantage.

At present, four separate transport systems handle four classes of fuels:

1. Liquid fuels (gasoline and diesel oil) in pipelines and tank trucks
2. Solid fuel (coal) in railroad cars, trucks, and barges or perhaps pulverized and slurried for pipeline transmission
3. Gaseous fuels (natural gas) in transmission and distribution pipelines
4. Condensable gases (LPG, propane) in long-distance pipelines and distribution in pressurized tanks (trucks).

Sections 2 and 10 discuss the ratings and quantitative evaluations of the various fuels for compatibility with energy transmission and distribution systems. The following is a summary of our assessments.

1. Synthetic Gasoline. For the network of pipelines, trucks, and service stations, synthetic gasoline is the most acceptable alternative. Pumps, lines, meters, and tanks can be used, and synthetic gasoline can be blended with conventional gasoline. The compatibility of synthetic gasoline is rated excellent.

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2. Distillates (Diesel Oils, Naphthas, Kerosene). From the standpoint of compatibility with transmission and distribution systems, distillates can be substituted for gasoline when blending with gasoline is prevented. Gasoline transmission pipelines and pumps can be used, but separate truck, tanks, and service station facilities are desirable. Blending with gasoline is impractical for internal combustion engine usage. The compatibility of distillates is rated good.

3. Alcohols (Ethanol, Methanol). Gasoline transmission pipelines and pumps can be used, but separate trucks, tanks, and service station facilities are desirable unless the alcohol is blended (as allowed by solubilities) with gasoline. Adulteration with water would most likely be illegal and must be guarded against. The fuel-handling compatibility of alcohols is considered good.

4. Heavy Fuel Oils, Residuals. Because of viscosity, these fuels are not transportable in gasoline pipelines, and tank trucks would need modifications, including pumps and perhaps heaters (depending on climate). Service station facilities also would have to be modified, and separate tanks would be required. The compatibility is rated poor.

5. Condensable Gases. Synthetic LPG and ammonia are fuels that are liquids at low pressures. LPG has its own long-distance transmission system, and ammonia could be transported (separately) in such lines. However, use of these fuels would necessitate changes in the distribution equipment now used for gasoline, and trucks built for conventional liquid fuels could not be used. Extensive service station modifications would be necessary. The compatibility of synthetic LPG and ammonia with distribution equipment is rated poor. Methylamine also is an easily condensed gas, but its toxicity requires sealed systems and transfers. It is an incompatible fuel.

6. Acetylene and Hydrazine. Acetylene gas decomposes explosively when compressed above 15 psig (2 atm). It cannot be transported in pressurized pipelines. Closed systems are desirable because it is an asphyxiant. It can be transported in a liquid state when dissolved in a solvent (acetone). New distribution and service station equipment would be required, and the acetone-acetylene solution would have to be transferred to vehicle tanks. Acetylene is unacceptable in terms of compatibility. Hydrazine is extremely toxic, and all fuel transport facilities would have to be sealed. It is normally transported and stored as a hydrate. New, sophisticated distribution and service station equipment would be required for its use (to service fuel-cell vehicles). Hydrazine is incompatible with present fuel transmission and distribution systems.

7. Gas Systems and Cryogenics (Carbon Monoxide, Hydrogen, Methane). Methane already has a transmission and distribution system (the natural gas system, which serves more than 40 million customers). With changes to the compressor stations, the meters, and some of the sealing and packing materials, hydrogen could be transported in this system. Except for the slight "leakiness" in this system, carbon monoxide also could be transported safely in it (as it was in the days of manufactured, or town, gas). Because of its toxicity, however,

carbon monoxide cannot be vented, making cryogenic storage impractical. Also, transfer systems would have to be sealed. In addition, the weights and volumes associated with gaseous carbon monoxide make it impractical to store or tank as a vehicle fuel. Hydrogen and methane can be liquefied for storage (with safe venting), and hydrogen can be hydrided to a solid. New service station facilities would be required, but tank trucks would be unnecessary if service stations performed the liquefaction (or hydride formation). We consider the compatibility of liquid hydrogen and methane to be fair and that of a metal hydride to be poor. Carbon monoxide is unacceptable.

8. Coal. Solids are incompatible with the present liquid and gaseous energy supply networks, but coal could be slurried for pipeline transport. It is hauled by train, truck, and barge. However, distribution to and storage at service stations would require all new facilities, and a convenient vehicle interface is not evident. Hence, the long-distance transport of coal is of good compatibility with existing systems, but distribution to service stations and vehicles is not compatible.

9. Special Features of Certain Fuels

- Acetylene. As indicated above, acetylene spontaneously decomposes (violently) and must be dissolved in a solvent, such as acetone, for storage. Although not toxic, it is an asphyxiant and an anesthetic.

- Ammonia. Because it can be catalytically decomposed to hydrogen and nitrogen, ammonia is a storage medium for hydrogen. Except for toxicity, storage (tankage) of liquid ammonia is practical.

- Carbon Monoxide. Carbon monoxide would have to be tanked as a compressed gas. Liquefaction is not practical because the toxicity requires complete containment, but heat leaks would cause excessive tank pressures and require venting. Further, filling warm containers with liquid carbon monoxide entails a great degree of venting unless a reliquefaction cycle or an oxidation process (to carbon dioxide) is employed.

- Ethanol. Because of its intoxicating characteristics and the legalities of transport and usage, ethanol would have to be denatured to prevent human consumption. Further, regulations would have to be invoked and metering equipment utilized to prevent illegal "watering down" of the fuel.

- Hydrazine. Hydrazine is considered because it is a preferred fuel for fuel cells — to produce electricity to power a motor to propel the vehicle. It is not considered for combustion in a heat engine.

- **Hydrogen.** The storage of hydrogen as a liquid offers some distinct advantages and disadvantages. Present-day technology indicates that, for long-term storage, the tank must be vacuum-insulated to avoid condensing liquid air from the atmosphere. But even with highly effective vacuum insulation, the tanks will eventually begin to vent hydrogen, which could be a flammability hazard.

6.2 Vehicle Tankage of Alternative Fuels

Table 6-1 lists some fuel data that affect storage or tankage on-board a vehicle. Table 6-2 summarizes the data from Table 6-1 plus selected data on heating value, flammability, and toxicity from Appendix A.

Fuel tank weights were calculated by first assuming that equal amounts of heat energy are needed for each fuel: the equivalent of 20 gallons of gasoline, or 2,246,000 Btu. For each fuel, a volume and weight for fuel alone are computed. (These appear in columns 2 and 3 of Table 6-1.) This computation inherently assumes that the fuels are utilized with the same efficiency (as gasoline) in a vehicle to yield identical performance, but does not take into account potential gains and/or losses in efficiency from engine designs suited for a particular fuel.

After calculating the volume requirements, we solicited estimates for tank weight, volume, and cost from commercial suppliers of containers (vessels, dewars, tanks, etc.). In some cases, the estimates are within about 20% of each other; however, in one case (liquid hydrogen), the estimates vary by a factor of 10. (These data are presented in columns 5, 6, and 7 of Table 6-1.) Currently available Dewar flasks that weigh about 400 pounds could accommodate the necessary 72.5 gallons of hydrogen. Estimates for the weight of improved vessels have been as low as 1 pound of tank per pound of liquid hydrogen (about 46 pounds for a 75-gallon tank). The lightweight tanks make use of advanced aerospace techniques[87] that might not be practical for automobiles.

Estimates of the weight of an advanced, but practical, tank have been made. For tanks with a short 'lock-up" time (time before hydrogen boil-off gases must be vented), the estimates are as low as 150 pounds.

Tanks for LSNG follow the same pattern as liquid hydrogen tanks, except that the overall weight is a little less. The LSNG tank is only about 40% the size of the hydrogen tank, but it must be stronger because methane is not

Table 6-1. FUEL TANKAGE SYSTEMS
(Energy Equivalent of 20 gal of Gasoline)

Fuel	Fuel Stored As	Weight (Fuel Only), lb	Volume (Fuel Only), gal	Fuel Tank Cost, 1973 dollars	Fuel Tank Weight, lb	Fuel Tank Volume, gal
Acetylene	Dissolved in Acetone	120	105	--	680	110
Ammonia	Liquid at 200 psi	279	43.4	125-175*	105	45
Coal	Dust	173.3	15.3	12-16† 50-80*	20-30	16
Diesel Oils	Liquid	121	17.0	11-13† 50-70*	25-30	18
Ethanol	Liquid	189	29.2	12-20† 50-80*	35-45	30
Gasoline	Liquid	117	20.0	11-13† 50-70*	25-30	21
Hydrazine	Hydrate	542	63.1	70-90*	165	65
Hydrogen (Gas)	Gas (2000 psi)	43	--	--	4600	--
Hydrogen (Liquid)	Liquid (−422°F)	43	72.6	200‡	≈ 150	103
Hydrogen (MgH_2)	Hydride	43	--	At least 340*	At least 700	At least 62
Kerosene	Liquid	117	17.3	11-13† 50-70*	24-26	19
LPG	Liquid	112	26.4	125-175*	65-75	27
Methanol	Liquid	247	38.9	12-20† 50-80*	50-55	41
SNG (Gas)	Gas	104	--	--	1100	--
SNG (Liquid)	Liquid	104	29.4	160*	≈ 60	43-46
Vegetable Oils	Liquid	139	18.3	10-13† 50-70*	25-28	20

* Estimated selling price.

† Estimated manufacturer's cost.

‡ Vendor's quoted price (mass-produced).

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Table 6-2. TANKAGE AND SAFETY PROPERTIES OF POTENTIAL FUELS

Fuel	Chemical Formula	Lower Heating Value, Btu/lb	Tankage Weight,[c] lb	Tankage Volume,[c] gal	Flammability Limits in Air, %		Ignition Temperature, °F	Dangerous for Prolonged Exposure, ppm
					Lean	Rich		
Acetylene	C_2H_2	20,780	800	390	2.8	80	581	Nontoxic[e]
Ammonia	NH_3	8,000	385	45	15	28	1200	100
Carbon Monoxide[a]	CO	4,350	2000	600	12.5	74	1128	100
Coal	C	10,000	200	18	d	d	d	Nontoxic
Diesel Oil or No. 2 Fuel Oil	Mix	18,480	150	22	--	--	494	500
Ethanol	C_2H_5OH	11,930	235	30	4.0	19	793	1000
No. 6 Fuel Oil	Mix	17,160	165	22	--	--	765	500
Gasoline	Mix	19,290	145	22	1.4	7.6	430	500
Hydrazine	N_2H_4	7,000	710	65	4.7	100	518	1
Hydrogen (ℓ)[b]	H_2	51,620	200	105	4.1	74	1085	Nontoxic[e]
Kerosene	Mix	19,090	145	22	0.7	5	491	500
LPG (synthetic)	C_3H_8	19,940	180	27	2.1	10	808	Nontoxic[e]
Methanol	CH_3OH	9,080	280	41	6.7	36	878	200
Methylamine	CH_3NH_2	12,860	260	35	4.9	21	806	10
Methane SNG (ℓ)[b]	CH_4	21,250	165	45	5.0	15	1170	Nontoxic[e]
Naphthas (approx)	Mix	18,850	150	22	1.1	6	430-530	500
Vegetable Oil (Cottonseed)	Mix	16,110	165	22	--	--	530	Nontoxic

[a] Gaseous.

[b] Cryogenic liquid.

[c] Energy equivalent of 20 gallons of gasoline.

[d] For coal dust, the flammability data vary with the type of coal. For dust of coal of medium volatility, the ignition temperature is about 1100°F. The minimum explosive concentration is about 50 oz/1000 cu ft.

[e] Asphyxiant.

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easy to vent safely and cannot be conveniently combusted catalytically as it goes overboard.

Metal hydride storage of hydrogen is another area of undefined commercial technology and constitutes part of the technology gap for the efficient automotive storage of hydrogen. Depending on the heat of formation of the hydride and its decomposition temperature, it may be possible to use the engine's cooling water or exhaust gas to liberate the fuel from the metal. On this basis, we estimated the cost of the tank alone and note it as the "at least" cost in Table 6-1.

Fuel-tank costs were estimated as closely as possible by using data from the manufacturers. Design configurations influence price, and when storage systems are not well-defined, costs are very uncertain. Some cost information was so vague that only two conclusions could be drawn. First, the cost of liquid hydrogen tanks can be substantially reduced by development and mass production. Current costs for the required 73 gallons might be as much as $1500, but one manufacturer thought that the price could be reduced to about $200. Second, the cost of metal hydride storage, based on current prices for magnesium, may be largely compared to that of gasoline. The estimated costs appear in Table 6-1.

The cost estimates given here are incidental information. Their assembly was part of an effort aimed at predicting the relative costs of alternative fuel utilization in a vehicle. Because vehicle mileage depends on power-plant efficiency and total vehicle weight, this cost can be estimated. However, a uniform and credible estimation procedure for engine efficiencies and the performance of alternative fuels in different types of power plants is beyond the scope of this study. As explained in Section 7, much of the required data is nonexistent or controversial.

6.3 Engine and Fuel Compatibility

The compatibility of possible engine and fuel cycles is discussed by summarizing each engine's combustion requirements and then each fuel's compatibility with that engine. The engines considered are as follows:

1. Conventional Otto-cycle engine
2. Open-chamber stratified-charge engine

3. Dual-chamber stratified-charge engines
4. Diesel engines
5. Brayton-cycle engines, gas turbines
6. Rankine-cycle engines, notably steam engines
7. Stirling cycle engines
8. Fuel cells.

6.3.1 Conventional Otto-Cycle Engines

For the conventional spark ignition engine, which uses no charge stratification, the following fuel characteristics are of importance when considering performance[65]: volatility, detonation and preignition characteristics, heat of combustion per unit mass and volume, safety, and chemical stability, neutrality, and cleanliness.

When emissions are considered, the effects of flammability limits become important, as illustrated in Figure 6-1. Obviously, for the fuel characterized by Figure 6-1 — a typical hydrocarbon — burning at lower equivalence ratios lowers emission of all three pollutant groups. As the mixture approaches the lower limit of flammability, hydrocarbon emissions begin to rise again. The lower a fuel's lean limit of combustion, the lower the air/fuel ratio at which the engine can be operated, thus lowering emission levels.

6.3.1.1 Acetylene

Acetylene has been used on an emergency basis as a substitute for gasoline. During World War II, many cars in Germany and Switzerland used gas generator units to produce acetylene for propulsion from calcium carbide and water. It proved to be a poor substitution.[5] Acetylene is very hard to handle because it tends to dissociate into carbon and hydrogen in fuel lines and manifolds, releasing heat and leading to high pressures. The risk of dissociation explosions can be lessened by dissolving the acetylene in water or another hydrocarbon fuel.

The use of acetylene as a fuel makes engine operation difficult. Its low octane number (40) makes operation at even moderately efficient compression ratios impossible, unless an excessively lean mixture is used or the acetylene is mixed with alcohol or water. Carbon deposits appear rapidly and maintenance may have to be doubled.

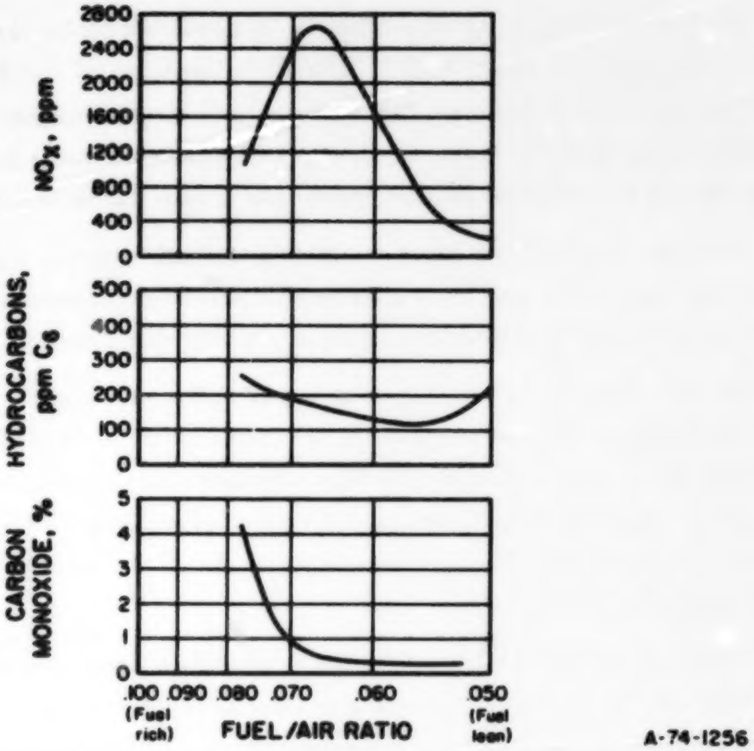

Figure 6-1. EFFECT OF EQUIVALENCE RATIO ON ENGINE EMISSIONS (Source: Ref. 56)

Most fuel tank or gas generator schemes are very heavy and/or bulky. In our opinion, acetylene is not well-suited for conventional, carbureted engines, although it may be usable in stratified-charge or other engines.

6.3.1.2 Ammonia

Ammonia has been intensively investigated as a fuel for spark-ignition engines,[1,17] primarily for military applications. The chief problem with ammonia apparently is its reluctance to ignite.[66] Increased spark energies and very accurate spark timing are required to initiate combustion, and researchers reported better combustion at higher compression ratios.[19] One alternative to high compression ratios (or supercharging to achieve the same operating pressures) would be partial dissociation into hydrogen and nitrogen before ignition. Most investigations, including those at General Motors Laboratories, have chosen this approach. Apparently, about 2-10% by weight dissociation is sufficient to begin modernately rapid combustion. A catalytic ammonia dissociator appears technically feasible.

The power output with ammonia is reported to be less than that with hydrocarbons by about 20%,[60] probably because of the lowered volumetric efficiency with a gaseous fuel. Most investigations reported that very high ignition energies[17] were required, and spark advance had to be greatly increased to compensate for ammonia's low flame velocity.

Whether emissions from ammonia-fueled engines are reduced is unclear. Carbon monoxide and hydrocarbon exhaust are of course eliminated. The potential for NO_x reduction is an area of controversy.

Sawyer and Starkman found that, despite ammonia's low peak-combustion temperature, NO_x were greatly increased.[53,60] In addition, General Motors Research Laboratories found that, at fuel-rich conditions, high concentrations of ammonia (5300 ppm) appeared in the exhaust gases.[17] These findings recently have been challenged by Hodgson,[28,32] who found low NO_x and dissociated ammonia.

Because ammonia is stored as a liquid and has a very high heat of vaporization, large amounts of heat are necessary for evaporation; however, ammonia is a gas at ambient temperature and pressure, and this heat could be supplied from engine exhaust and/or the atmosphere.

6.3.1.3 Carbon Monoxide

No data are available for engines run on carbon monoxide alone. The National Bureau of Standards investigated it briefly during World War II before deciding that alcohol was a better alternative to gasoline. The Bureau found that the octane number of carbon monoxide could not be expressed on the usual scale.[51]

During World War II, automobiles were adapted to operate on producer gas,[5] which is mainly carbon monoxide and hydrogen. Power was reported to have been decreased 50%, probably because of the displacement of combustion air by the gaseous fuel. Compression ratios were raised to 8:1, but this did not increase output to the gasoline-fueled level.[5]

Like other gaseous fuels, carbon monoxide would offer advantages in cylinder-to-cylinder fuel distribution, cold starting, and avoidance of vapor lock. However, its toxicity would require careful construction of fuel systems to avoid disastrous leaks.

6.3.1.4 Coal

Coal is not compatible with conventional internal-combustion engines because it is a solid fuel.

6.3.1.5 Diesel Oils

Diesel oils are not volatile enough for use with carburetors[15]: fuel injection would be required. However, the low octane quality, the deposit-forming tendencies, and the difficulty of cold-engine starting make diesel oil very poor fuel for conventional engines.

6.3.1.6 Ethanol

Ethanol has been the subject of many separate investigations, most of which were concerned with gasoline-alcohol blends; these were summarized by Bolt in 1964.[9]

Because of its low heating values, alcohol reduces the overall heating value of the fuel when it is added to gasoline. Many investigations into the performance of unmodified, conventional engines have shown the effect of leaner mixtures, "surge," slight loss of power, and roughness during warm-up. However, when air/fuel ratios were adjusted to reflect the stoichiometry of the blend, observers concluded that any effects were minimal.[40]

A prime motivation for blending ethanol with gasoline is the resulting increase in octane number. Ethanol's octane numbers are 106 (RON) and 89 (MON), compared with about 93 (RON) and 85 (MON) for regular gasoline. Large amounts of blends (greater than 10% of total gasoline sales) have been used in Europe.[9]

Tests on gasoline with up to 30% ethanol as fuel showed no substantial improvement in emissions over pure gasoline.[40]

The use of pure ethanol requires some modifications to conventional engines, but can produce satisfactory results. Ethanol-fueled engines have been shown to produce up to 8% greater power output if run richer than stoichiometric.[62] Tests by the National Bureau of Standards showed ethanol did less damage than gasoline to cylinder walls and oil.[13] With its high octane number, ethanol is suitable for high-compression engines. However, engines running on ethanol will not start below 58°F, unless fuels of higher volatility, usually naphtha or diethyl ether, are blended with them. These compounds reportedly[13] sometimes lead to vapor lock at about 90°F.

Because of the high latent heat of vaporization of ethanol, some type of manifold heating arrangement would be needed. Brooks[13] found pure ethanol slightly more efficient than gasoline, whereas Starkman et al.[62] have presented results that suggest it may be slightly less efficient. Seemingly, engine design is the dominant factor. Certainly, using ethanol as a fuel would allow an increase in compression ratio, because of ethanol's high octane number relative to that of unleaded gasoline. The estimated increase in efficiency should be about 10% when the compression ratio is raised[65] from 8:1 to 11:1. Apparently, ethanol has no great effect on emissions.[61,62]

In summary, ethanol-gasoline blends are quite compatible with present engines, and pure ethanol would require some modifications. However, its use presents no great efficiency advantages.

6.3.1.7 Gasoline

Gasoline-like fuels (C_5-C_{10}) manufactured from alternative energy sources, principally coal or oil shale, are expected to be compatible with present automobile engines. Gasoline from the Canadian Tar Sands is already in use. Prior to 1960, there was little reason to consider alternative fuels; gasoline was satisfactory. However, two new considerations have entered the picture: emissions and energy efficiency.

The efficiency of automobile engines has dropped in recent years because of the need to reduce pollution, and vehicle efficiency has decreased because of increased weight. The proportionate causes for efficiency losses are debatable.

There seems to be some agreement that an emission-controlled, 4200-pound car goes about 85% as far per gallon as precontrolled cars—a 15% loss.[16,34,67,89,90] There is no agreement, however, on the total loss that will be incurred in meeting 1977 Federal Standards. Estimates range from 15% losses [46,67] to 25-30% losses.[16,18] With dual catalysts and a better air/fuel ratio management system, however, some of the losses may be recouped by the time the 1977 Federal Standards are met.

6.3.1.8 Heavy Oils

Heavy fuel oils are incompatible with conventional spark-ignited engines because of high viscosity, poor volatility, and many of the same reasons previously enumerated for diesel oils. Residual oils have additional problems because of their great sulfur content and the damage done by the ash content of combustion products.

6.3.1.9 Hydrazine

We found no evidence that hydrazine has ever been used as a motor fuel (flame combustion in a heat engine). We included it in this study only as an energy carrier for fuel cells.

6.3.1.10 Hydrogen

The use of hydrogen in conventional engines would require that all the problems of engine conversion to gaseous fuels be overcome, plus several difficulties arising from hydrogen's extreme physical properties. Operation of engines using modified propane carburetors shows that hydrogen precombusts in the intake manifold.[22] The flame speed of hydrogen is so high that, with near stoichiometric mixtures, "knock" results from rapid flame propagation.[8] Various solutions to these problems have been used; none are entirely satisfactory. Exhaust gas recirculation,[23] a combination of a very clean engine (free of dirt, oil, or deposits) and a low coolant temperature, and water injection are among the methods used.[8]

Once "knock" is under control, operation on hydrogen is described as ideal. Hydrogen engines idle very smoothly (and at very low rpm), experience no warm-up roughness, and respond well to changing load. However, a great deal of combustion air is displaced by gaseous hydrogen, so the charge is diluted. (Hydrogen's low volumetric heating value makes it worse in this respect than other gaseous fuels.) As a result, power from hydrogen-fueled engines is reduced considerably. At UCLA, a medium-sized V-8 (351 cubic inches) engine fueled with hydrogen gives performance similar to that of a small six-cylinder engine.[22] Interest in hydrogen engines continues, however, because of the low emissions and the efficient use of chemical energy.

If lubricants and other contaminants are kept out of the combustion chamber, emissions of carbon monoxide and hydrocarbons are eliminated when hydrogen is used as a fuel. Nitric oxide, which is the only significant pollutant proved in engine tests, can be controlled by judicious regulation of the air/fuel ratio. However, the possibility exists that hydrogen peroxide also could be a combustion product, and hydrogen-engine emissions tests should be conducted to determine this. Figures 6-2 and 6-3 show data on CFR* engines taken at General Motors Laboratories and JPL[11, 63]; there is reasonably good agreement. These experiments indicate that peak NO$_x$ concentrations

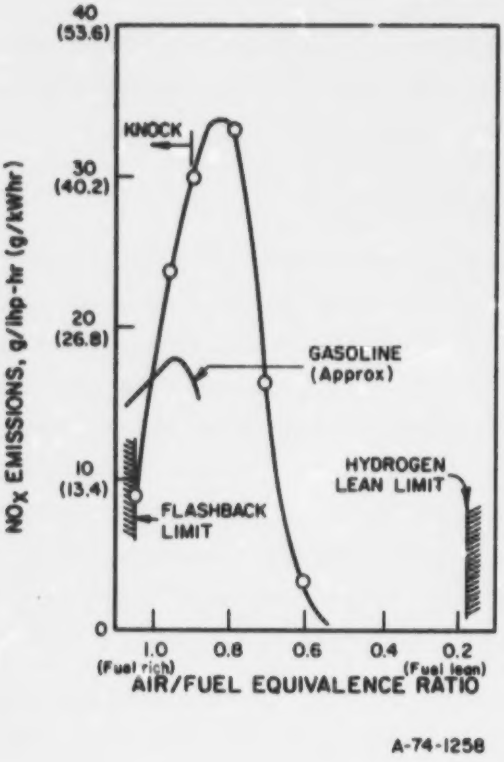

Figure 6-2. NO$_x$ EMISSIONS FROM GENERAL MOTORS LABORATORIES' CFR ENGINE OPERATING ON HYDROGEN (Source: Ref. 63)

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* CFR = Cooperative Fuel Research.

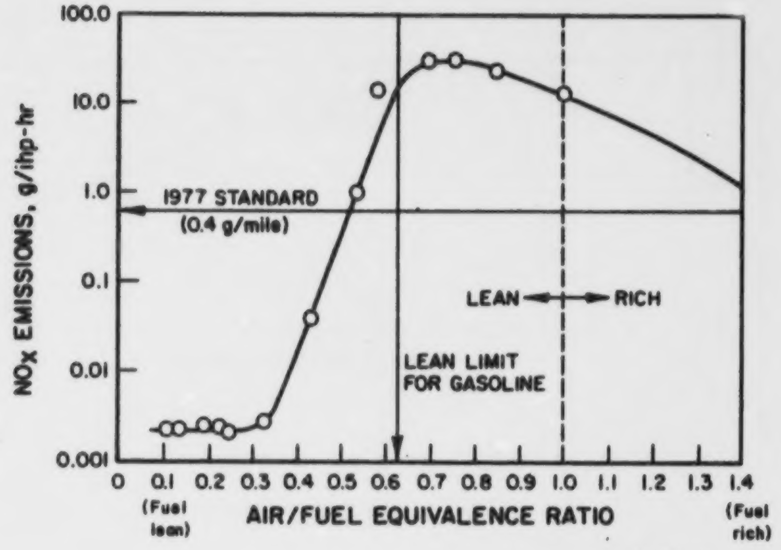

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Figure 6-3. EMISSIONS FROM JPL'S CFR ENGINE OPERATING ON HYDROGEN (Source: Ref. 11)

are as bad or worse for hydrogen than for gasoline, but that hydrogen's very low lean limit of combustion (equivalence ratios of 0.1-0.2 for hydrogen versus 0.6-0.8 for gasoline) offer a low- to medium-load operating region in which NO_x emissions are virtually zero. The problem of high NO_x at peak power (near stoichiometric region) remains to be solved.

In addition to lower emissions, there is another reason why the ultra-lean region, where hydrogen burns but hydrocarbons do not, can be beneficially exploited. The first cars to run on very lean hydrogen have shown significant increases in efficiency.[23] Figure 6-4 shows how thermal efficiency is increased by operation in the very lean region.[11] This is the result of the decreased dissociation of combustion products as peak cycle temperatures are reduced and the high polytropic expansion exponent, which allows the indicated efficiency to approach the ideal.[10] JPL has recorded a decrease of 34% in energy demand per mile for a V-8 engine operating in this region. (The fuel was gasoline supplemented with just enough hydrogen to make it flammable.)[11]

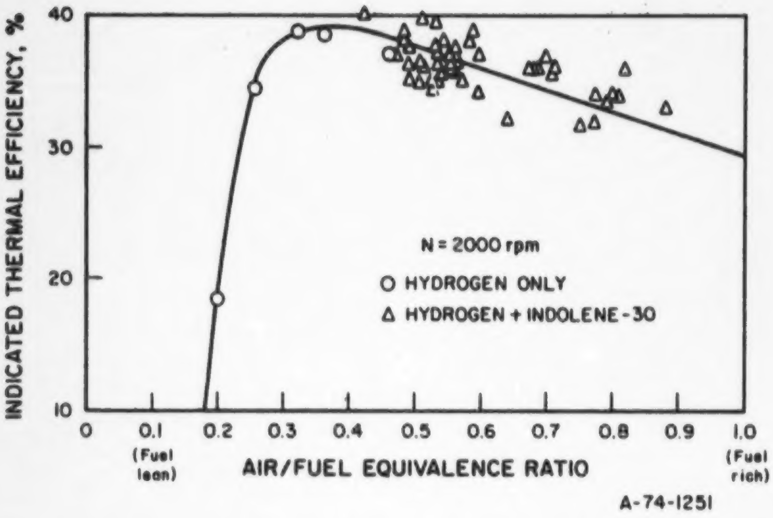

Figure 6-4. THERMAL EFFICIENCY OF JPL'S V-8 ENGINE OPERATING ON HYDROGEN (Source: Ref. 11)

The UCLA car reportedly can go 200 miles on 10^6 Btu, even though it weighs 4000 pounds.[23] This figure remains valid for urban driving and compares favorably with the 193 miles/10^6 Btu that the EPA calculates for the Mercedes diesel (over the Federal Driving Cycle).[12]

Additional opportunities exist for increasing efficiency. Swain and Adt of the University of Miami have made use of hydrogen's wide flammability limits to eliminate throttling as a means of load control.[64] In their scheme, engine output is determined by the amount of fuel injected at low pressure into the intake stream. This eliminates the intake manifold "pumping" losses experienced at partial throttle and, in effect, allows the engine to regulate output in the same way that a stratified-charge engine does, but without using high-pressure fuel injection. Swain and Adt claim a 50% increase in energy mileage (miles/Btu) for this system.[3]

Hydrogen is not completely compatible with conventional engines, but offers some impressive incentives for conversion.

6.3.11 Kerosene

The reasons for kerosene's poor compatibility with conventional engines are much the same as those for other fuel (diesel) oils. Model T Ford engines, tractor engines, and other very-low compression-ratio (4:1) Otto-cycle engines have been operated on kerosene after the engine is completely warm. However, kerosene's low volatility, its tendency to form deposits, and its low octane quality make it generally incompatible.

6.3.1.12 SLPG

If the proper fuel system is used, LPG is quite compatible with conventional engines. Appropriate fuel systems already have been designed, and propane-fueled cars have been in operation for some time.[33,55]

LPG has the same advantages as other gaseous fuels – easy starting, quick warm-up, better fuel distribution, simplified carburetion, and smooth idling. The disadvantage also is the same: About 10% of the peak power is lost because the gaseous fuel displaces combustion air.[36]

Propane has a lower lean limit of combustion than gasoline, and for this reason, emissions can be reduced when switching from gasoline to propane. Figures 6-5 and 6-6 show the regions where propane is burned.[32] Carbon monoxide also is reduced by lean running, but for most hydrocarbons, carbon monoxide concentration is a function of equivalence ratio and is really not affected by fuel characteristics. The less complicated fuel molecules in LPG (butane, propane) should produce less reactive hydrocarbons than the more complicated molecules in gasoline.

As with other gaseous fuels, users of propane report that less maintenance is necessary and that frequently replaced components (spark plugs, oil filters, oil) last longer.[55]

Because propane can be burned at lower equivalence ratios than gasoline (because of its slightly wider flammability limits and better fuel distribution), an improvement in fuel economy – on the basis of miles per Btu – can be expected. Efficiency also can be increased by raising compression ratios because of LPG's high octane quality (RON = 109; MON = 96).

6.3.1.13 Methanol

Methanol is a liquid fuel like gasoline, and the same storage and carburetion systems can be used if the physical and combustion properties of methanol are taken into account.

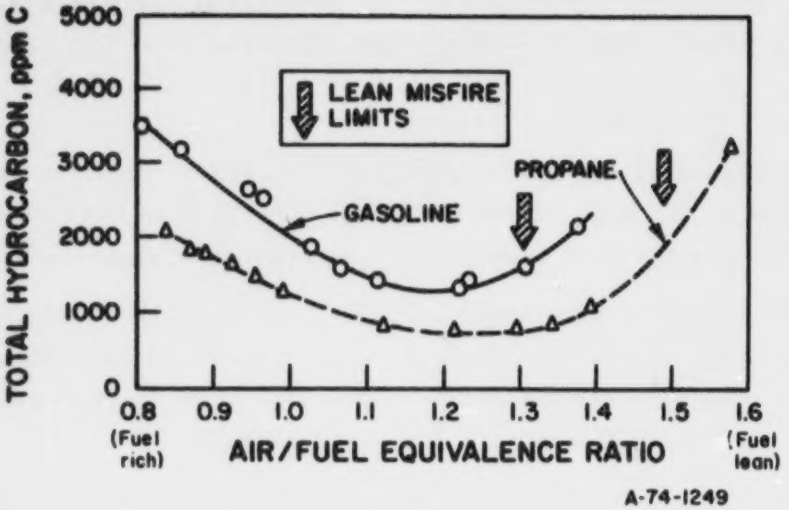

Figure 6-5. HYDROCARBON EMISSIONS AS A FUNCTION OF AIR-FUEL EQUIVALENCE RATIO AT 50% THROTTLE (Source: Ref. 55)

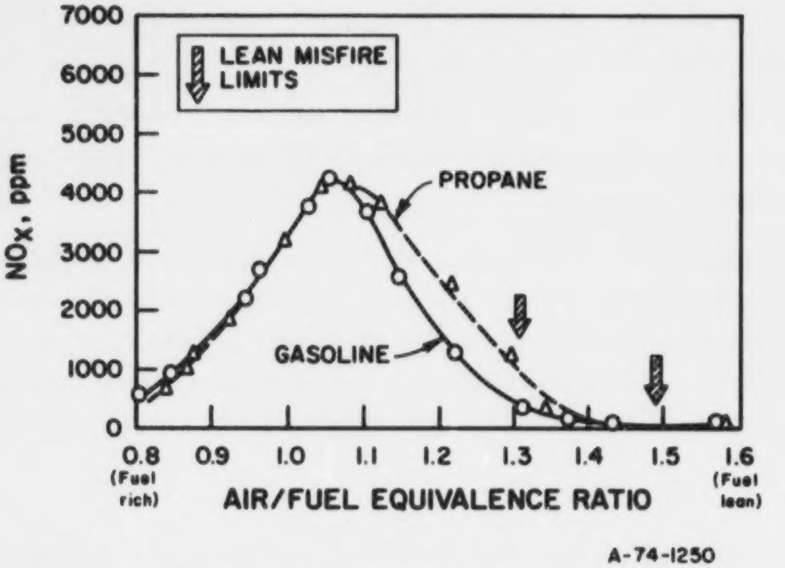

Figure 6-6. NO_x EMISSIONS AS A FUNCTION OF AIR-FUEL EQUIVALENCE RATIO AT 50% THROTTLE (Source: Ref. 55)

Methanol has a high flash point, similar to that of ethanol. Early researchers had trouble starting ethanol engines in moderately cold weather.[13] For starting below temperatures of 40-50°F, volatile agents, such as ethers or acetone, must be added; electric heaters also have been suggested.[2]

Methanol's heating value is one-half that of gasoline, and its latent heat of vaporization is about 4 times as high. Therefore, 8 times as much heat must be supplied for methanol vaporization as for gasoline vaporization, the usual procedure is to route exhaust gases through the intake manifold.[1] Many sources have assumed that the incoming charge is cooled during fuel evaporation and that this increases volumetric efficiency and peak power[9]; this idea was challenged by Starkman.[62] Because of methanol's low heating value, fuel systems must be modified for greater fuel flow rates.

Apparently, some of methanol's properties can be utilized to make spark-ignition engines more efficient. Some researchers have found that only 70% as much energy per mile was needed with methanol and that emissions remained at a low level.[7] Methanol's low lean limit of combustion extends the operating region of methanol engines greatly,[20] as Figure 6-7 shows, and has the advantage of reduced emission of hydrocarbons, carbon monoxide, NO_x, and more efficient operation. Furthermore, because this low-emissions region is available, less drastic measures are necessary to meet emissions standards.

Burning in the lean region, methanol has another advantage over gasoline: Its flame speed does not fall off as fast when the mixture is air-rich. Figure 6-8 shows the results of experiments in an internal combustion engine by Starkman, Strange, and Dahm.[58] The fact that methanol's flame (reaction front) speed stays high is important. One effective way to lower NO_x emissions is to retard ignition, which results in lost cycle efficiency. Because methanol's flame speed is faster than that of gasoline, this lost efficiency is recovered.[1]

The last important property of methanol is its low peak combustion temperature, about 180°F less than that of gasoline, significantly lowering the rate of NO_x formation.[1]

Methanol has one peculiar emissions problem. Researchers have noted increased emissions levels of aldehydes, especially for lean mixtures.[20] The seriousness of this emissions problem, however, has not been determined.

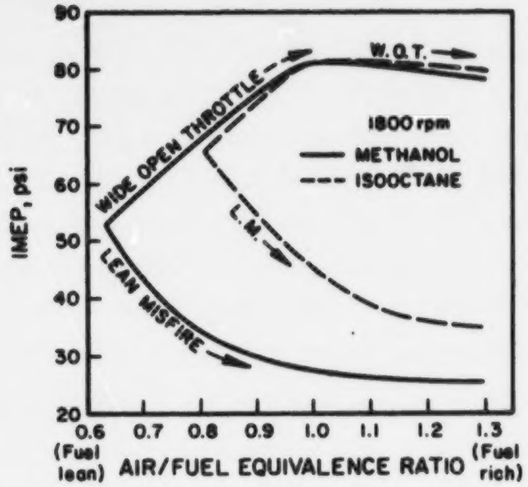

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Figure 6-7. OPERATING REGIONS FOR METHANOL AND ISOOCTANE
(Source: Ref. 20)

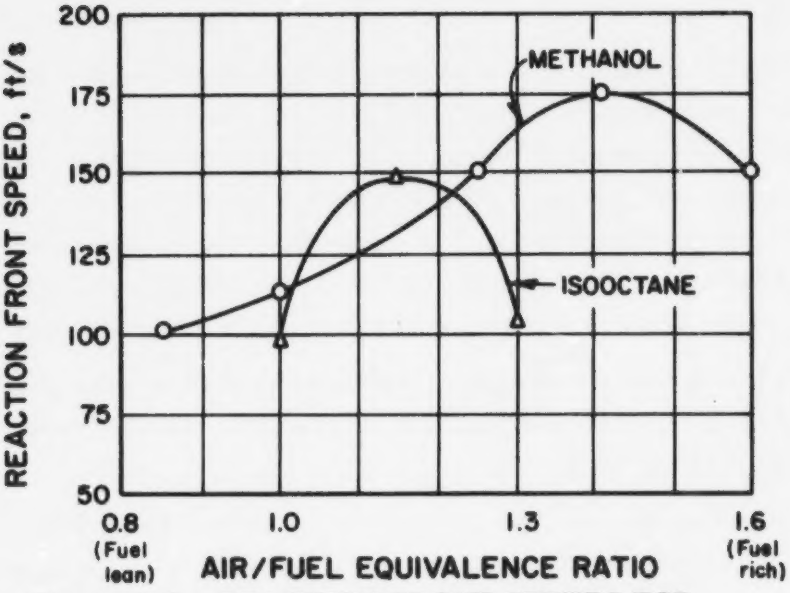

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Figure 6-8. REACTION FRONT SPEEDS FOR METHANOL AND ISSOCTANE
(Source: Ref. 58)

The fuel economy and emission performance of an internal combustion engine optimized for operation on methanol is unknown — obviously a research gap. However, a Gremlin modified for methanol by Adleman et al. of Stanford University almost passed the 1977 Federal Standards — without resorting to exhaust gas recirculation.[1]

6.3.1.14 Methylamine

Methylamine is an easily liquefied gas produced from ammonia and natural gas or methanol (through synthesis gas), and it is a conveniently handled fuel (except for toxicity). Because methylamine is a condensable gas, it would require a propane-like fuel system for automotive use. Its heating value is lower than that of hydrocarbons. No octane ratings exist, but methylamine has a convenient flash point (0°F).

Methylamine contains chemically bonded nitrogen and there are indications that bound nitrogen is easily converted to NO_x.[44] Impurities containing bound nitrogen may be a significant source of NO_x even in hydrocarbon flames. The probability is high that NO_x formation would be a severe problem with methylamine.

6.3.1.15 SNG

Because no SNG is now available for automotive tests, performance must be inferred from experiments with simulated SNG or natural gas.[4,21,24]

Methane shares the advantages of LPG; i.e., the fuel is distributed as a gas. The natural gas fuel system is similar to the LPG fuel system except that it needs no evaporator, unless the SNG is stored as a liquid. Cars designed for natural gas idle more smoothly and have better fuel distribution and warm-up characteristics than gasoline-fueled cars. They also can be operated in the same lean region as propane (air/fuel equivalence ratio greater than 1.0); see Figures 6-9 and 6-10.

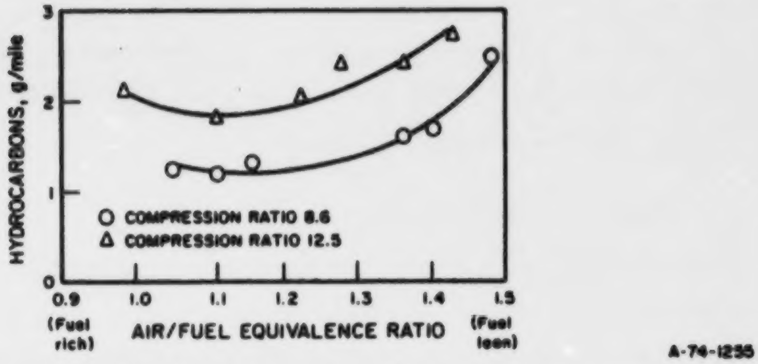

Figure 6-9. HYDROCARBON EMISSIONS FROM AN SNG-FUELED ENGINE
(Source: Ref. 4)

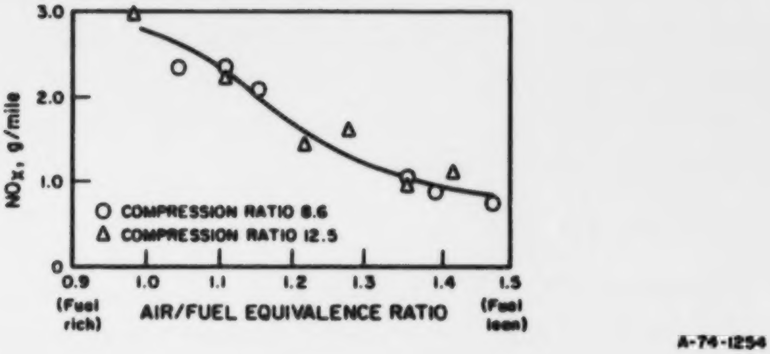

Figure 6-10. NO_x EMISSIONS FROM AN SNG-FUELED ENGINE
(Source: Ref. 4)

Tests with natural gas have indicated that although hydrocarbon and NO_x emissions are reduced, SNG-fueled cars will not escape the need for exhaust treatment to meet the 1977 Federal Standards.[4] (See Figure 6-9.)

Methane has a very high octane number (RON = 130), and the hydrogen that is expected to appear in SNG will not lower it. For this reason, compression ratios can be raised to as high as 12.5:1, which improves fuel economy about 10%, according to Allsup.[4]

The drop in peak power is generally higher for methane than for propane,[55] which is to be expected, because it is a lower-molecular-weight hydrocarbon and because the fuel displaces more intake air. This loss in volumetric efficiency can be recouped, if the methane is stored as a cryogenic liquid and if the air intake manifold is cooled by cold methane gas before combustion in the engine.[36]

6.3.1.16 Naphthas

Only a few engine experiments have been performed with naphthas: the National Bureau of Standards operated engines on 25% naphtha and 75% ethanol during World War II. These tests indicated that small amounts of naphtha could be satisfactorily burned with alcohol. Naphtha's octane number (50-60) is too low for it to be used alone.

6.3.1.17 Vegetable Oils

Apparently no conventional spark-ignited engines have been run on vegetable oils. They are not volatile, and in experiments with diesels, some vegetable oils had to be preheated before being given to the fuel injectors.[35] They probably are not suitable for conventional engines.

6.3.2 Open-Chamber Stratified-Charge Engines

The open-chamber stratified-charge engine uses high-pressure fuel injection to obtain the following advantages[47]:

a. Detonation at any compression ratio and fuel/air ratio can be decreased.

b. Low-octane fuels can be utilized at high compression ratios.

c. Load control can be achieved without air throttling, because combustion is localized. This feature increases the economy of part-load operation.

d. The overall lean air/fuel ratios at part load result in good fuel consumption and constitute an approach to the theoretical limit of engine efficiency.

The term "stratified charge" comes from the gradient in air/fuel ratios that exists after injection. The area around the fuel jet is rich because the fuel is breaking up into fine droplets and evaporating. The air/fuel ratio varies from ultra-lean (definitely outside the jet) to stoichiometric (where proper amount of fuel has evaporated) to very rich (definitely inside the jet). Combustion is initiated by a spark plug, and, in principle, this is the only difference between stratified-charge and diesel engines.

In general, fuels used in stratified-charge engines range from methane to No. 2 diesel fuel; all fuels in this range give good performance.[19] Fuel injection also frees the engine from any volatility concerns. Open-chamber engines are characterized by high fuel economy (up to 30% better than comparable carbureted engines[46]) and lower emissions.

All liquid hydrocarbon fuels (fuel oils, kerosenes, gasolines, naphthas), except heavy oils, are well-suited to stratified-charge engines. The high viscosity of heavy oils as well as their ash and sulfur content may make them impractical as fuel. Gaseous hydrocarbon fuels (methane and propane) have been used, although no test data are available.[19] Note that fuel injection eliminates the power loss due to displaced intake air usually associated with gaseous fuels.

Because coal dust is solid, abrasive,and difficult to combust completely and produces some ash, it probably would not be a good fuel. Hydrazine also would be impractical because of chemical instability; it could explode in the fuel injection system.

The suitability of the other fuels for the stratified-charge engine is as follows:

- Acetylene. Acetylene should be a useful fuel; however, the problem of spontaneous, explosive dissociation must still be solved.

- Ammonia. Tests by Pearsall show that anhydrous ammonia could be used in a high-compression (12-16:1) engine, which should probably be supercharged to retain a good specific output.[49] No data on emmissions are available, but ammonia would probably not follow the pattern of hydrocarbon fuels.

- Carbon Monoxide. This fuel probably could be used.

- Ethanol. The low energy density and high latent heat of vaporization could cause problems. Four to five times as much heat must be supplied to the jet for evaporation (compared with that for a liquid hydrocarbon fuel). Otherwise, ethanol should be acceptable.

- Hydrogen. No test data have been published for stratified-charge engines, per se. However, Schoeppel's injected Clinton engine is very similar to the stratified-charge engine, and hydrogen works well in it.[45, 54] It probably would be a good fuel.

- Methanol. Methanol requires about 8 times as much fuel (by volume) for fuel vaporization purposes as liquid hydrocarbon fuels; this requirement would change the injection system requirements considerably. On the other hand, methanol's lower lean limit of combustion may extend the combustion zone further away from the core of the injection spray, perhaps reducing NO_x emissions.

- Methylamine. Methylamine could be a good fuel if NO_x emissions are not excessive.

- Vegetable Oils. Cottonseed oil has been used in diesels and is a good fuel.[35] If the greater viscosity of vegetable oils (compared with those of hydrocarbons) is not a problem, they should be a useful fuel.

6.3.3 Dual-Chamber Stratified-Charge Engines

The dual-chamber stratified-charge engine was developed specifically for low emissions. Two combustion chambers are used, each with its own carburetion system. Except for the comments on emissions, the descriptions from the section on conventional engines (Section 6.3.1) apply here, also.

6.3.4 Diesel Engines

The diesel engine has advantages — in emissions and in fuel economy — over other engines. Because they are designed for very high compression ratios and do not usually throttle intake air, diesels are the most efficient engines on the road and will probably be so for a long time. The emissions of a 3500 pound Mercedes Benz automobile as investigated by Southwest Research Institute and the EPA, approach the 1977 limit. If the 1977 NO_x limit is relaxed to 2.00 grams/mile, the diesel could be within all the standards with only modest modifications.[57] Diesels do, however, have a problem with exhaust odor, which is not currently subject to regulation.

Diesel engines are not insensitive to fuel characteristics. Diesel fuels should have good "ignition quality," i.e., a short delay period, the time between start of ignition and an appreciable rise in pressure.[65] Some of the fuels considered here have poor ignition quality and therefore are unsuitable for use in compression-ignition engines. In general, the best fuels for diesel engines are the distillate hydrocarbons (fuel oils, kerosene).

- Acetylene. Because acetylene has a high heat of combustion per standard cubic foot, it was investigated as a diesel fuel; it was found to be impractical.[65]

- Ammonia. Ammonia was tested in a compression-ignition engine and found to be an unsuitable fuel.[49, 59]

- Carbon Monoxide. Carbon monoxide probably is only suitable for use in dual-fuel engines. In such a case, it would be inducted through the intake valve, and a high compression ratio could be retained because of carbon monoxide's high octane number. This would reduce the volumetric efficiency somewhat, but this is a minor consideration in diesels except at peak load.

- Coal. Dr. Rudolph Diesel at first tried to operate his newly invented engine on solid fuel (coal). Powdered coal and even sawdust have been used to run internal-combustion engines in isolated cases. The elaborate apparatus required to prepare and inject such fuels, together with the difficulties due to solid residue (ash), have so far prevented successful commercial application.[65]

- Ethanol. Alcohols are not good fuels for injection into compression-ignition engines.[65] However, ethanol has been used in conjunction with residual oils as a power booster. At a compression ratio of 22:1, up to 36% alcohol was carbureted into the engine where the heavier fuel was injected. When greater percentages of alcohol were used, knock occurred.[31]

- Gasoline. Because of its very low cetane number, gasoline generally is unsuitable for use in diesel engines. It has been used in divided-chamber engines, and Ricardo[31] was able to run a supercharged diesel smoothly on an unspecified fuel with a cetane number of 18. There are no data on emissions.

- Heavy Oils. Heavy oils have been burned with alcohol and by adding ignition accelerators to the fuel. Wear is increased, and ignition accelerators are expensive.[31] Despite a long-standing economic incentive for constructing an engine to burn residuals, there has been no great success with them.

- Hydrazine. No data are available on hydrazine. Injection may be difficult.

- Hydrogen. Hydrogen may be an acceptable fuel for diesel engines. Homogeneous mixtures of hydrogen and oxygen diluted by argon have been compression-ignited by Karim and Watson.[37] No work on injection in compression-ignition engines was found.

- LPG. Gaseous fuels are not injected into diesel engines in the same manner as liquid fuels. Propane, when used in diesel engines, is inducted with the air and then is compressed and ignited by the injection of a high-cetane fuel. This scheme is very similar to spark ignition.[65] Compression ratios are limited to about 14:1. The power is slightly lower than that from a diesel of the same compression ratio.[36]

- Methanol. No data were uncovered for methanol in diesel engines. It should be as unsuitable as ethanol. Alcohols are not good diesel fuels.[65]

- Methylamine. No reports on methylamine in diesel engines were found. Injection as a liquid should be possible, but no data on ignition quality exist.

- Natural Gas. Methane is burned in the same way as LPG.

- Naphthas. No data are available for naphthas as diesel fuel. Naphtha is composed of straight-chain and cyclic molecules, has a moderate overall octane number, and most probably has a low cetane number. The gasoline-like components may make naphthas a poor diesel fuel.

- Vegetable Oils. Vegetable oils have been used successfully as diesel fuel. Cottonseed oil has been shown to be a promising fuel that produced horsepower comparable to that produced by diesel oil. The corrosion caused by cottonseed oil is about the same as that for diesel oils. Starting is no more difficult, and engine thermal efficiency is increased slightly.[35]

6.3.5 Brayton-Cycle Engines

Gas turbine engines are attractive because they have steady-flow combustion, which is easier to control than Otto-style cyclic combustion. For this reason, gas turbines have legendary fuel versatility. They were heavily investigated by Chrysler Corp. in the early 1960's, and 50 experimental models were actually built and tested.

Gas turbines have been run successfully on fuels ranging from methane to residual oils.[66] Coal has been used in some power-industry applications.[68] Gasoline, kerosene, fuel oils,and diesel oils have been omitted from the discussion of fuels because the generally available performance figures in the gas turbine are about the same.

New gas turbine combustion designs are often tested on a variety of fuels. In the past, few emission data have been taken, but recently for a development program sponsored by the EPA, emission data were taken.

- Ammonia. An ammonia gas turbine engine was built for the Army in International Harvester's Solar Division.[14] It was found to be more troublesome than hydrocarbon fuels. The ammonia must be introduced in the vapor phase; the vaporizer adds to the cost and complexity of the engine. However, the thermal efficiency of the engine was about 2.5% higher, and (apparently by rich running) about 10-20% more power could be extracted from the same engine.

- Coal. Coal has been used for stationary applications, but the ash content must be screened out by several rows of turbine blades, making the overall engine quite heavy.[69]

- Carbon Monoxide. No data were found on carbon monoxide gas turbines.

- Heavy Oils. Residuals have been used; they have a tendency to smoke.[66] Requirements for complete combustion might necessitate an increase in the nominal residence time of the fuel in the combustion chamber, and this could lead to high NO_x emissions.

- Hydrogen. In the 1950's, NACA (NASA's predecessor) operated a gas-turbine engine on hydrogen successfully in an airplane; however, no data were taken on emissions.[41]

- LPG. In the EPA gas turbine combustion development program, General Electric used LPG as its check-out fuel.[67] In tests of continuous combustion systems, propane produces fewer emissions than liquid fuels.[15]

- Methanol. In a paper published in June 1973, LaPointe and Schultz[39] of Ford Motor Co. report that the use of methanol in gas turbines gave only about 25% as much nitric oxide as diesel fuel. This difference is attributed to methanol's lower (by 200°F) peak-combustion temperature and the strong temperature dependence of the nitric oxide formation mechanism. Hydrocarbon and carbon monoxide levels were increased by methanol.

- Methane. Gas turbines have been operated on methane, and nitric oxide emissions are much lower than from propane.[48]

We could obtain no published data on the use of acetylene, carbon monoxide, hydrazine, or vegetable oils as diesel fuel.

6.3.6 External-Combustion Engines

Rankine and Stirling engines depend on heat only. The heat source can be anything, decaying nuclear isotopes, electrical resistance heat, or, as in most cases, hot gases from combustion.[68] For this reason, any of the fuels listed will be satisfactory, providing the external burner is designed to take into account the proper flow rates, flame speeds, etc. The more volatile fuels may produce fewer emissions, however.

6.3.7 Fuel-Cell Power Plants

Theoretically, all 18 potential automotive fuels selected for study could be used as the fuel for a fuel cell. Fuel cells generally are classified according to 1) the type of electrolyte or ion-conducting media used and 2) the operating temperature, as shown in Figure 6-11. With the exception of coal, which would first have to be gasified, and hydrogen, which is already present in a usable form, the other 16 potential automotive fuels could be used as the

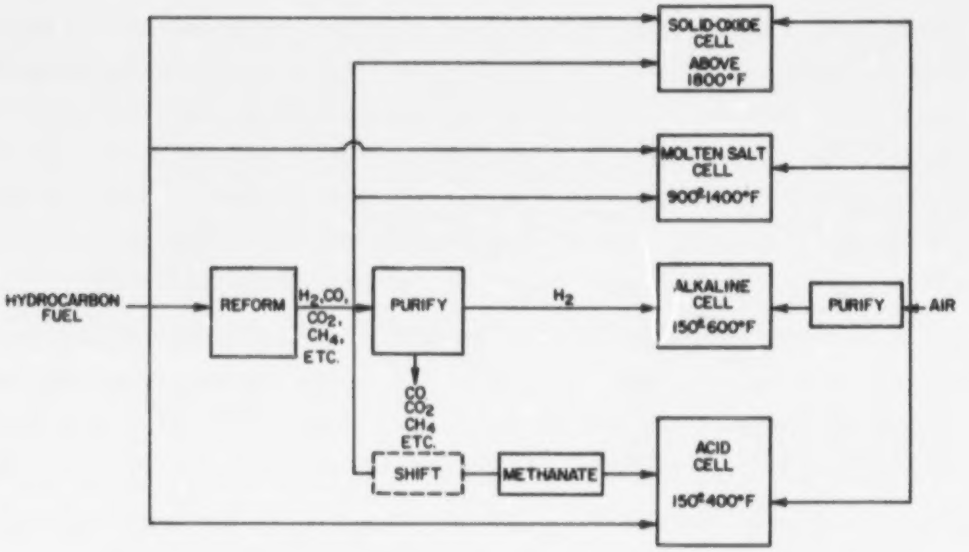
SOLID-OXIDE CELL
ABOVE 1800°F
MOLTEN SALT CELL
900°-1400°F
HYDROCARBON FUEL
REFORM
H_2, CO, CO_2, CH_4, ETC.
PURIFY
H_2
ALKALINE CELL
150°-600°F
PURIFY
AIR
CO
CO_2
CH_4
ETC.
SHIFT
METHANATE
ACID CELL
150°-400°F
A-72-652

Figure 6-11. FUEL CELL TYPES

hydrocarbon fuel, as shown in the figure. However, considering the state-of-the-art and historical advancements during the development of each type of fuel-cell system, the choice of system and applicable fuels is quickly reduced to only a few easily cracked or reformed hydrocarbons and to fuel cells containing either acid or alkaline electrolytes.

6.3.7.1 High-Temperature Fuel Cells (>1000°F)

During the past two decades, numerous programs have been initiated to commercially develop this type of fuel cell. Cells operating above about 1000°F have basically two desirable features:

a. Hydrocarbon fuels can be utilized directly.

b. Cheap electrocatalysts for the electrodes are possible.

As a result, a great variety of hydrocarbon fuels can be utilized rather inexpensively either directly or indirectly, as shown in Figure 6-11. However, numerous undesirable features make their use in vehicular applications remote; e.g.,

- High operating temperature
- Low power-to-weight ratio for molten carbonates
- Brittleness of solid oxide electrolyte.

The high operating temperature (generally greater than 1000°F) of these cells is the primary reason that these cells probably will never be used in automobiles. Unless their temperature is maintained near the operating level (which would result in very inefficient overall operation in most cases), the thermal cycling from ambient temperature to operating temperature causes large, thermally induced stresses of the cell components, resulting in failure due to cracking and/or loss of electrochemical activity.

For molten carbonate fuel cells, the additional disadvantage of a low power-to-weight ratio would result in large, bulky, and unacceptably heavy power plants. In addition, such a power plant also requires carbon dioxide in the oxidant, which would necessitate the recirculation of the anode effluent.

Solid oxide cells that operate at an even higher temperature, 1800°F, have the inherent disadvantage of extremely thin, fragile, and brittle electrolytes. These electrolytes must be thin (less than 0.01 inch thick) to obtain acceptable performance; therefore the feasibility of fabricating more durable cells is zero. As a result, the prospect of using thin, fragile solid oxide cells operating at 1800°F in a vehicle that is constantly undergoing varying G-forces (acceleration, deceleration, bumpy roads, impacts, etc.) is very remote.

6.3.7.2 Moderate-Temperature Fuel Cells (150°-600°F)

Tremendous progress has been made on these systems in the last two decades, mainly as a result of huge Government-sponsored programs aimed at the development of systems capable of supplying the electrical power required for space travel. The Gemini series used acid ion-exchange electrolyte fuel cells developed by General Electric Co., and the more recent Apollo series used alkaline fuel cells developed by Pratt & Whitney Aircraft. Both systems reached the extremely high levels of sophistication and reliability required for such duty; the reactants (hydrogen and oxygen) were supplied by cryogenic means. However, both systems are theoretically capable of operating on a hydrocarbon fuel and air, as shown in Figure 6-11. Complete purification of fuel and air to free them from carbon dioxide is difficult but essential if alkaline electrolytes are to be used. Although the acid system can utilize a hydrocarbon directly, the resulting performance is generally poor. As a result practical systems require the indirect use of the fuel, i.e., either reforming, cracking, or partial oxidation to form a hydrogen-containing product.

At present, only two major fuel-cell-development programs are active. One program is at Pratt & Whitney Aircraft and the other is a joint program between Alsthom (a division of the French company, CGE) and Exxon Corporation. Numerous other smaller programs are being carried out, such as as those at Union Carbide (U. S.), Shell Oil Ltd. (England), Monsanto (U. S.), the Institute of Petroleum (France), and Hitachi, Ltd. (Japan).

Because most of the work on fuel cell systems has been done for nonvehicular applications, obtaining a meaningful and accurate component cost breakdown is very difficult. However, we attempt to estimate some approximate figures based on the literature information currently available, together with the following assumptions:

a. Only fuel cells operating near ambient conditions, such as those containing either acid or alkaline electrolytes, will be available for use in vehicular applications prior to the year 2000.

b. Fuels will be available in the following order of decreasing desirability: hydrogen, methanol, ethanol, and methane.

These two assumptions are perhaps more easily discussed with the aid of Figure 6-11, which shows both the types of fuel cells available and the possible fuel and oxidant choices. We think the alkaline cell and the acid cell have the best possibility for vehicular use for two reasons:

a. Their technology is the most advanced.

b. Their overall efficiency of operation would be the highest because the least amount of heat would be wasted during rest conditions to keep the cells heated and ready for instant operation and response.

The second assumption (choice of fuels) was made because for vehicular use fuel cells must operate on hydrogen or an easily reformed hydrocarbon. This constraint is necessary because, at present, no direct* hydrocarbon fuel cell is available with the high performance necessary to satisfy the weight and volume requirements of vehicular use.

Using these assumptions and ground rules, we have estimated the costs for the three major subsystems mentioned above based on published information; see Table 6-3. This tabulation is purely an estimate based on laboratory results and vendor quotations for similar hardware applications.

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* A direct hydrocarbon fuel cell is one that can utilize the hydrocarbon without a reforming step.

Table 6-3. ESTIMATED FUEL CELL COSTS

Subsystem	Fuel Cell Type: Acid ($/kW)	Fuel Cell Type: Alkaline ($/kW)
Fuel Pretreatment	25[a]	50[d]
Oxidant Pretreatment	Not necessary	10[d]
Hydrogen Tank	7-10[b]	7-10[b]
Fuel Cell	200-350[c]	35-85[b] 50[e]
Motors and Controls	25-30[b]	25-30[b]
Total Cost		
Hydrogen/Air	232-390	77-135
Hydrocarbon/Air	250-405	120-175

[a] Source: Ref. 25.

[b] Source: Ref. 50.

[c] Source: Ref. 42.

[d] Because the reformer for an alkaline system also must have a purifier so that only pure hydrogen enters the cells, we have estimated that the fuel treatment for the alkaline system will cost twice as much as that for the acid system. Similarly, because the oxidant cleanup is rather simple compared to fuel reforming, we have assumed that the cost of the oxidant pretreatment will be less than one-half of that of the fuel pretreatment.

[e] Source: Ref. 38.

Part of the difference in costs for the acid and alkaline systems can be attributed to design: The acid system is designed to operate for 16,000-40,000 hours in stationary power-plant applications, whereas the alkaline system is designed to operate for much shorter periods of time — probably on the order of 2000-4000 hours — in vehicular applications. In any event, although the wide price range ($77/kW to $405/kW) indicates the uncertainty of the estimate, it nevertheless demonstrates the rather high costs that can be expected for fuel-cell power plants in vehicles. For example, the Funk study,[50] which was based on using a 16.6 kW peak power fuel cell to power a Renault 4L (2090 pounds loaded weight, including approximately 450 pounds of effective load), estimated that it would cost between 40 and 72% more than a comparable conventional vehicle. No comparable costs are available for the Kordesch vehicle, which as an Austin A-40 weighing 2000 pounds and which was powered by a 6 kW fuel cell and 4kWhr battery (16 kW peak output) in parallel. This vehicle was actually built and operated for thousands of miles. The range on one filling of hydrogen was more than 200 miles; its top speed was 55 mph.

Realistic estimates of the thermal efficiency and weight of the propulsion system are rather difficult because most of the fuel-cell-development work has been done either for space applications[43] requiring extremely reliable, lightweight (4 lb/kW), and sophisticated systems or for stationary power applications[27] for which cost is the only concern and weight (20-88 lb/kW) and volume are secondary. The fuel cell systems cited above have the following characteristics:

- Kordesch[38]: fuel cell system, 60 lb/kW, ~50% conversion efficiency; lead acid batteries, 20 lb/kW.
- Institut Francais Du Petrole[50]: fuel cell system, 20-33 lb/kW, ~50% efficiency at full power.

Because of the embryonic stage of development of fuel-cell-powered vehicles, estimates of maintenance costs would be meaningless at this time.

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7. ENVIRONMENTAL EFFECTS AND RESOURCE DEPLETION

7.1 Environmental Effects

The comparison of environmental effects due to most alternative fuel systems is necessarily incomplete at the present state of technology. A fuel system is composed of resource extraction, fuel synthesis, transportation and storage, distribution to the vehicle, and fuel utilization in the vehicle power plant. To evaluate alternative fuel systems from the aspect of environmental damage, each system component should be characterized and the overall effect determined.

The environmental damage caused by the introduction of waste heat and material pollutants or waste products depends on the fuel synthesis process, the fuel-handling and -delivery system, and the general performance of the automotive power plant. For a given production level, synthesis pollutants, such as sulfur, can vary by a factor of at least 5, depending on the type of coal used. The volume of shale residue can vary by a factor of 3, depending on the grade of shale and the efficiency (recovery) of the process.

In general, we do not recommend that pollution due to a system component be developed into a selection criterion because this component cannot indicate overall pollution or resource depletion effects. The exception to this is the use of coal (solvent-refined) in vehicle engines. We cannot deal with total environmental pollution (which should be a selection criterion) because the efficiencies, emissions, and performances of the various system components are not known with precision. In most cases, estimates of these would be conjecture.

7.1.1 Fuel Consumption and Emissions

The environmental effects of potential alternative fuel systems are impossible to assess. For most cases, the efficiency and emissions are not known accurately or precisely (with a stated degree of error). Approximations or estimates contain biases and cannot allow for the use of emission control devices installed on engines.

7.1.1.1 Efficiency

For the vast majority of engine-fuel combinations, efficiencies have not been measured. Therefore, the specific fuel consumption and the quantity of exhaust can only be estimated from a fuel's chemical and (presumed) combustion properties. The EPA is now measuring fuel consumption for conventional (Otto cycle) engines and for diesel engines. Performance in stratified-charge engines will soon be known, but performance in Brayton, Rankine, and Stirling cycle power plants can only be estimated. There are reports on several alternative fuels in (modified) engines, e.g., ammonia, ethanol, methanol, hydrogen, methane, and LPG in spark-ignited internal combustion engines. Information on these fuels was presented in Section 6. These data can be used to characterize these combinations, but cross comparisons with unmeasured combinations are without precision. Therefore, any selection criterion based on the efficiency of various fuel-engine combinations is indeterminate at this time.

7.1.1.2 Exhaust Emissions

For the various fuel-engine combinations, emissions have not been measured, except for specific cases, e.g., ammonia, ethanol, methanol, hydrogen, methane, and LPG in spark-ignited internal combustion engines. Complete cross comparisons are not valid because emissions from unmeasured combinations are conjecture. Further, the uncertain future of automobile emission regulations and the potential use of emission control devices make even the measured pollutant levels less of a determinant. Therefore, fuel-engine emissions cannot be used to conclusively aid in the selection of alternative fuels at this time.

7.1.1.3 Coal Emissions

The synthetic liquid and gaseous fuels that are potential alternative automotive fuels contain one or more of the following elements: carbon, oxygen, hydrogen, and nitrogen. The combustion products are either nonpollutants (carbon dioxide, water), or they are pollutants that can be reduced to acceptable levels by emission control devices (carbon monoxide, NO_x, hydrocarbons). Such control devices are now under development.

Coal itself is not a synthetic fuel, and in natural occurrence it contains carbon, oxygen, hydrogen, nitrogen, sulfur, ash, mercury, and other heavy metals (chlorides and oxides). If the coal is solvent-refined, some polluting materials are removed, but much remains. The content of solvent-refined coal is sensitive to the raw coal content. Table 7-1 shows a typical analysis of the common elements in solvent-refined coal.

Table 7-1. SOLVENT-REFINED COAL
(Pittsburgh and Midway Coal Mining Co.)

	Raw Coal	Solvent-Refined Coal
	wt %	
Typical Products		
Carbon	70.7	88.2
Hydrogen	4.7	5.2
Nitrogen	1.1	1.5
Sulfur	3.4	1.2
Oxygen	10.3	3.4
Ash	7.1	0.5
Moisture	2.7	--
Heating Value	12,800 Btu/lb	15,800 Btu/lb

If the solvent-refined coal were combusted in a vehicle engine, the following products would have to be contained to prevent environmental damage (in addition to carbon monoxide, NO_x, and hydrocarbons).

- Sulfur dioxide (gas), 7-8 grams/mile (Table 7-1)
- Ash (silicon dioxide, aluminum oxide, ferric oxide, and calcium oxide solids), 3-5 grams/mile (Table 7-1)
- Metals: trace vanadium and mercury.

In conclusion, we consider solvent-refined coal to be a speculative alternative fuel on environmental grounds. It is eliminated in the near term because of a technology gap in the on-board vehicle control of emissions.

7.1.2 Synthesis Plants and Effluents

From Section 3, the probable energy/material resources are coal and oil shale, and the additional possible resources are nuclear and solar energy. The types of pollution for fuel systems vary according to the resource.

7.1.2.1 Coal to Clean Fuels

Process characterizations for clean liquid and gaseous fuels from coal are described in Appendix B and in Section 5. Table 7-2 lists the potential pollutants from coal for a gasification plant producing 250 million CF/day (240 X 10^9 Btu/day) of pipeline gas from Illinois No. 6 coal (3.7% sulfur).

Table 7-2. POLLUTION FROM COAL PROCESSING
(250 Million CF/Day SNG Plant)

Pollutants	Range of Emissions
Sulfur (Primarily as Hydrogen Sulfide)	300-450 tons/day
Ammonia	100-150 tons/day
Hydrogen Cyanide	0 to possibly 1 ton/day
Oil and Tars	Trace to 400 tons/day
Mercury	Less than 5 lb/day
Ash Residue	1000-3000 tons/day

Ranges are given in Table 7-2 because of variations among gasification processes and because of the uncertainties in some yields. A plant producing 250 million CF/day of pipeline gas (250 X 10^9 Btu/day) consumes between 12,000 and 22,000 tons/day of coal, depending on the process and the rank of the coal.

7.1.2.2 Oil Shale to Clean Fuels

Section 5 contains information on process routes to clean liquid and gaseous fuels from oil shale. The total quantity of potential emissions for an oil shale plant producing 50,000 bbl/day of oil (280 X 10^9 Btu/day) from 30 gal/ton of oil shale are shown in Table 7-3. Appendix B contains more details.

Table 7-3. POLLUTION FROM OIL SHALE PROCESSING
(50,000 bbl/Day Shale Oil Plant)

Pollutants	Emissions
Sulfur (Primarily as Hydrogen Sulfide)	About 150 tons/day
Ammonia	About 150 tons/day
Spent Shale	About 47,000 tons/day

7.1.2.3 Nuclear and Solar Energy

Nuclear plants and the pollutants associated with them are discussed in Section 5. Solar energy conversion, in general, is the least polluting conversion process, but a usable automotive fuel is not the direct product; a chemical fuel must be synthesized from steam, electricity, or plant growth (crops). Except for electrolysis of water to produce hydrogen (and oxygen), material as well as thermal pollution result. Qualitatively, pollutants from nuclear and solar processes are as follows:

- Nuclear Plants: gaseous and solid nuclear fission products of various half-lives; fissile uranium and plutonium, tritium and induced radioactive isotopes; and waste heat
- Solar Plants: despoiled land area, concentrated waste heat, and agricultural wastes.

Within the scope of this study, quantitative comparisons cannot be made among such things as shale residue, coal ash, fission products, and acres of land devoted to solar collectors or crops. The types of environmental effects are different, and ecological damage occurs to varying degrees. Further, future technology development for land reclamation and waste treatment or containment will alter these pollution effects in an unpredictable manner. Moreover, these environmental effects are only a few of those attributable to an alternative fuel system. Hence, selection criteria for fuel systems based on synthesis plant pollution would be incomplete and would lack objectivity, although subjective judgments might be made.

7.2 Resource Depletion

To determine whether large differences in resource depletion are required by the candidate fuels using coal and oil shale resources, we formulated and calculated three resource depletion models by using reasonable efficiencies for fuel production and utilization. Because some coal-to-fuel processes are more efficient than others, some fuels require smaller amounts of resources to satisfy automotive demand. In addition, fuel comparison is complicated by the by-products of fuel synthesis. Some processes produce substantial amounts of by-product fuels (e.g., oils or high-Btu gas) with wider uses than the raw material, whereas other processes have by-products with little or no thermal use (e.g., waxes, tars, or ammonia). Heavy fuels, such as residual oils, can be burned in fossil-fueled central power stations as low-sulfur replacements for coal, so the coal demand is reduced by a factor of 1. Tars and ammonia, on the other hand, were not assumed to reduce the demand for coal.

For comparison, then, we have set up a simplistic model of U.S. coal consumption for 1985 and 2000. These years were chosen because the synthetic fuel industry will be operating on a large scale by then. The following assumptions were made:

1. The demand for automotive transportation energy was established by Model I as 20.0×10^{15} Btu in 1985 and 30.3×10^{15} Btu in 2000. Also, methanol-fueled automobiles were assumed to be 10% more efficient than hydrocarbon-fueled cars, and the use of hydrogen in vehicles was assumed to be 30% more efficient. For comparison, the calculation also was made for 1985 by using Model II assumptions (automotive energy demand = 19.1×10^{15} Btu). Note that Model II, although it assumes a greater total energy demand and supply, allows for large, post-1985 imports; thus, the amount of coal mining in Model II is actually less than that in Model I.

2. To accentuate the differences, we assumed that all automotive requirements would be met with shale- and coal-derived fuels.

3. Quantities of by-product fuels were obtained from process flow sheets. (These processes are described briefly in Section 5 and summarized in Tables 5-1 through 5-6. Very detailed process descriptions are presented in Appendix B.) Low-Btu gas and heavy oils made as by-products of synthetic fuel production were credited against coal demanded by electrical generation and other coal-burning industries. These needs were estimated by Models I and II. Ammonia, phenols, tars, and waxes were assumed to be of no heating value because they would probably not be used as fuels.

4. The process synthesis efficiencies are taken from the descriptions cited in 3 above. These efficiencies are not overall energy efficiencies. They are the efficiencies with which the processes produce the individual products or by-products. They are the ratio of the heating value of the particular product to the total energy input to the process. Hence, by-product synthesis efficiencies are inherently low.

5. Production of oil from oil shale was limited to 1.0 X 10^6 bbl/day in 1985 and 3.5 X 10^6 bbl/day in 2000. The balance then was filled in with coal liquids. The assumed oil shale assay was 25 gallons of oil per ton of shale.

For each fuel, we have used this model together with the fuel-synthesis product and by-product lists from Appendix B to calculate the total amount of coal or oil shale that must be mined to meet the demands of gasification, automotive fuel, and industrial and electrical needs for coal. A representation of the model appears in Figure 7-1. The calculations made appear in Tables 7-4, 7-5, and 7-6 and are summarized in Tables 7-7 and 7-8.

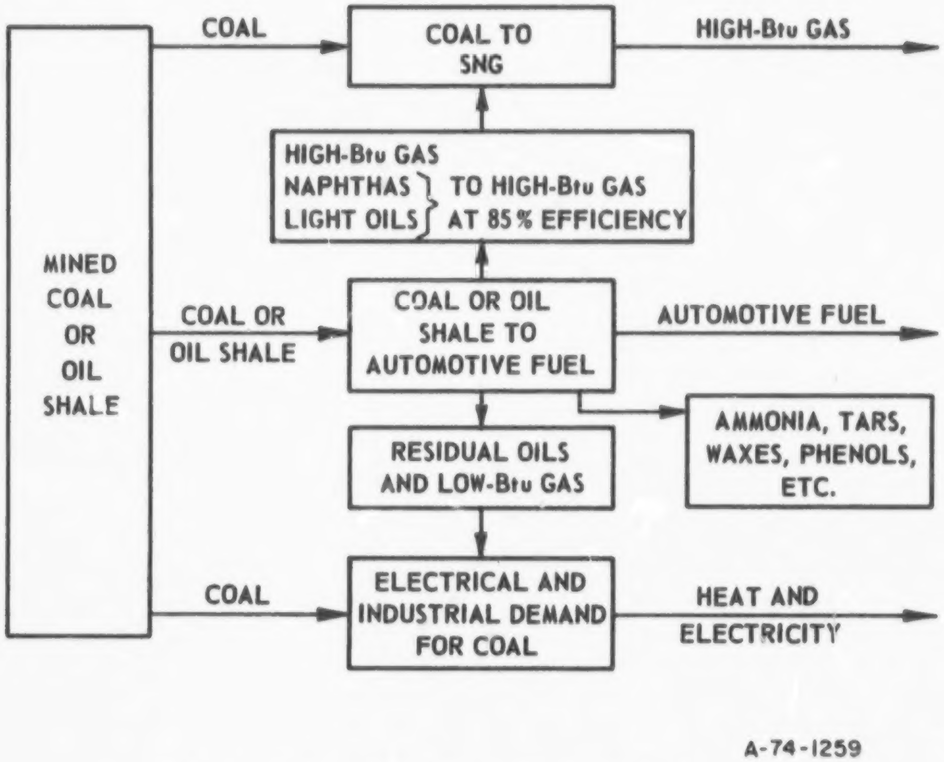
MINED COAL OR OIL SHALE
COAL
COAL TO SNG
HIGH-Btu GAS
HIGH-Btu GAS
NAPHTHAS
LIGHT OILS
TO HIGH-Btu GAS AT 85% EFFICIENCY
COAL OR OIL SHALE
COAL OR OIL SHALE TO AUTOMOTIVE FUEL
AUTOMOTIVE FUEL
AMMONIA, TARS, WAXES, PHENOLS, ETC.
RESIDUAL OILS AND LOW-Btu GAS
COAL
ELECTRICAL AND INDUSTRIAL DEMAND FOR COAL
HEAT AND ELECTRICITY
A-74-1259

Figure 7-1. SCHEMATIC DIAGRAM OF RESOURCE DEPLETION MODEL

Table 7-4. RESOURCE DEPLETION IN 1985 ACCORDING TO MODEL I

Fuel	Use	Demand, 10^{15} Btu	Synthesis Efficiency, %	By-product Credit	Demand for Coal	Demand for Coal	Total Coal Demand
				10^{15} Btu		10^{9} tons	
LSNG From Coal by Lurgi Process	Automobile fuel	20.0	47.2	--	42.4	2.04	
	Coal and oil from coal (industrial and electrical)	26.5	5.9	2.50	24.0	1.15	3.19
Methanol by Koppers Totzek, ICI Processes	Automobile fuel	18.0	40.0	--	45.0	2.16	
	Coal and oil from coal	26.5	--	--	26.5	1.27	3.43
Coal to Gasoline and Distillate Oils by CSF Process	Automobile fuel	20.0	44.8	--	44.6	2.14	
	Coal and oil from coal	26.5	15.4	6.87	19.6	0.94	3.08
Coal to Liquid Hydrogen	Automobile fuel	15.4	35 (est)	--	44.0	2.12	
	Coal and oil from coal	26.5	--	--	26.5	1.27	3.39
Oil Shale to Gasoline and Distillate Oils	Automobile fuel	1.9	59.4	--	--	0.58 (shale)	
	Coal and oil from coal	26.5	5.7	0.18	20.3	0.97 (coal)	
	Additional coal for automotive fuel	18.1	44.8	--	40.4	1.94 (coal)	3.49 (coal and oil shale)
	Coal to residual oil	--	15.4	6.22	--		

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Table 7-5. RESOURCE DEPLETION IN 2000 ACCORDING TO MODEL I

Fuel	Use	Demand, 10^{15} Btu	Synthesis Efficiency, %	By-product Credit	Demand for Coal	Demand for Coal	Total Coal Demand
				10^{15} Btu		10^{9} tons	
LSNG From Coal by Lurgi Process	Automobile fuel	30.3	47.2	--	64.2	3.09	
	Coal and oil from coal	34.2	5.9	3.79	30.4	1.46	4.54
Methanol by Koppers Totzek, ICI Processes	Automobile Fuel	27.3	40.0	--	68.3	3.28	
	Coal and oil from coal	34.2	--	--	34.2	1.64	4.92
Coal to Gasoline and Distillate Oils by CSF Process	Automobile fuel	30.3	44.8	--	67.6	3.25	
	Coal and oil from coal	34.2	15.4	10.41	23.9	1.14	4.39
Coal to Liquid Hydrogen	Automobile fuel	23.3	35 (est)	--	66.6	3.20	
	Coal and oil from coal	34.2	--	--	34.2	1.64	4.84
Oil Shale to Gasoline and Distillate Oils	Automobile fuel	6.7	59.4	--	--	2.02 (shale)	
	Coal and oil from coal	34.2	5.7	0.64	25.4	1.22 (coal)	
	Additional coal for automotive fuel	23.6	44.8	--	52.7	2.53 (coal)	5.77 (coal and oil shale)
	Coal to residual oil	--	15.4	8.11	--	--	

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Table 7-6. RESOURCE DEPLETION IN 1985 ACCORDING TO MODEL II

Fuel	Use	Demand, 10^{15} Btu	Synthesis Efficiency, %	By-product Credit	Demand for Coal	Demand for Coal	Total Coal Demand
				10^{15} Btu		10^9 tons	
LSNG From Coal by Lurgi Process	Automobile fuel	19.1	47.2	--	40.5	1.95	
	Coal and oil from coal (industrial and electrical)	23.7	5.9	2.39	21.3	1.02	2.97
Methanol by Koppers Totzek, ICI Processes	Automobile fuel	17.3	40.0	--	43.2	2.08	
	Coal and oil from coal (industrial and electrical)	23.7	--	--	23.7	1.14	3.22
Coal to Gasoline and Distillate Oils by CSF Process	Automobile fuel	19.1	44.8	--	42.6	2.05	
	Coal and oil from coal (industrial and electrical)	23.7	15.4	6.57	17.1	0.82	2.87
Coal to Liquid Hydrogen	Automobile fuel	14.7	35 (est)	--	42.0	2.02	
	Coal and oil from coal (industrial and electrical)	23.7	--	--	23.7	1.14	3.16
Oil Shale to Gasoline and Distillate Oils	Automobile fuel	1.9	59.4	--	--	0.58 (shale)	
	Coal and oil from coal	23.7	5.7	0.18	17.6	0.85 (coal)	
	Additional coal for automotive fuel	17.2	44.8	--	38.4	1.84 (coal)	
	Coal and oil from coal (industrial and electrical)	--	15.4	5.91	--		3.27 (coal and oil shale)

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Table 7-7. SUMMARY OF RESOURCE DEPLETION IN 1985 AND 2000 ACCORDING TO MODEL I

Fuel	Coal Mined 1985	Coal Mined 2000
	—10⁹ tons/yr—	
Gasoline, Distillates From Coal	3.08	4.39
Methanol From Coal	3.43	4.92
LSNG From Coal	3.19	4.54
Liquid Hydrogen From Coal	3.39	4.84
Gasoline and Distillates From –		
Oil Shale*	0.58	2.02
Coal	2.91	3.75
	3.49	5.77

* See assumption 5.

Table 7-8. SUMMARY OF RESOURCE DEPLETION IN 1985 ACCORDING TO MODEL II

Fuel	Coal Mined, 10^9 tons/yr
Gasoline, Distillates From Coal	2.87
Methanol From Coal	3.22
LSNG From Coal	2.97
Coal to Liquid Hydrogen	3.16
Gasoline and Distillates From –	
Oil Shale*	0.58
Coal	2.69
	3.27

* See assumption 5.

Note that the quantities given in Tables 7-4 through 7-7 are based on particular processes for fuel synthesis, and we have taken into account certain differences in fuel utilization efficiencies (according to assumption 1).

In conclusion, some differences in the amount of resource depletion will occur, depending on the alternative fuel that is synthesized. There is a definite indication that about 10% more coal would be required to support methanol synthesis (versus gasoline and distillate oil synthesis), regardless of the time frame. SNG production (including liquefaction) requires slightly more coal than liquid-hydrocarbon-fuel production but less coal than hydrogen production. For the processes and products considered, the largest total mining requirements would occur if oil shale is used for gasoline and distillate oil synthesis and coal is used solely for methanol synthesis. When gasoline and distillate hydrocarbons are the synthesized fuels, the inclusion of oil shale as an energy and material resource decreases coal-mining requirements by 5-15%, but increases overall mining requirements by 15-30%.

8. ALTERNATIVE FUEL SYSTEM ECONOMICS

A complete cost assessment of an alternative fuel for automotive use comprises the costs of the following system components:

- Resource extraction and delivery
- Fuel synthesis plant operation
- Fuel transmission, storage, and distribution (including service station)
- Fuel utilization costs (in the vehicle).

For this study, the economic assessments have been made in two tiers. The first tier, denoted as "preliminary" costing, has been performed for most of the potential fuels – those that seemed possible after consideration of natural resource availability and fuel properties and safety. We have made the second-tier effort for the most promising, or "candidate," alternative fuels after an initial fuel selection had been made. The methodology of Section 2 (based on preliminary costs) was applied to determine these candidate fuels. We have not considered excise or road taxes for fuels.

For the first tier, the cost ranges (in 1973 dollars) have been determined by using a simplified DCF costing procedure. Some guidelines of this procedure are as follows:

a. The capital cost for the processes involved is obtained by a search of the literature or by an estimation based on similar industrial plants.

b. An annual operating cost of 20% of the capital cost is determined, together with return on investment, depreciation, maintenance, operating labor, operating supplies, insurance, and taxes.

c. An additional operating cost is assigned for the cost of the resource base and utilities supplied.

d. Items b and c are combined to obtain the total estimated operating cost. From this total and the plant throughput, a unit production cost for the fuel is obtained.

. Raw material costs assumed are coal, 25¢-35¢/10^6 Btu ($6.25-$8.25/ton); water, 10¢-30¢/1000 gal; oil shale, $1.00/ton; and nuclear heat, 60¢/million Btu.*

The cost estimates from this procedure are based largely on data published during 1965-73, and a simplistic (but uniform) financing model has been applied. Proponents of various energy conversion methods are often overly optimistic in their economic assessments. They tend to underestimate such important costs as charges for interest, labor, and utilities and to overestimate energy efficiencies. To develop an alternative fuel system and to construct and operate the synthesis plants, present-day costs would significantly exceed those listed in Table 8-1. These more realistic considerations have been made in our second-tier costing effort for the candidate fuels.

8.1 Costs of Resource Extraction and Fuel Synthesis (Preliminary)

The raw material costs assumed are typical of those in the recent literature. The costs for raw material extraction have been determined by a survey of current mining costs for coal or oil shale. These costs will increase in future time frames, excluding inflation; the cost of oil shale mining, which is now much lower than that of coal, will rise as deeper or lower-oil-content shale must be mined. Future costs of strip-mined oil shale may exceed those of coal (per Btu), and the small price advantage shown for oil-shale-based fuel systems in Table 8-1 will disappear and eventually become reversed. The rate of raw material supply is based on an estimate of the process energy efficiency. Ethanol synthesis costs are determined from the work of Miller[11] in producing industrial alcohol from wheat and from Hanson *et al.*,[7] who consider two processes using corn. For methanol from wood chips, we assume wood chip costs (including land charges, growing and harvesting costs, and chipping) to be approximately those of Szego and Kemp.[22]

From a refining standpoint, the syncrude produced from coal or oil shale has much the same properties as conventional crude oil. Existing refineries can treat it with only small modifications. For refining cost estimation, the methodology outlined in articles in the *Oil and Gas Journal* by Nelson[13, 14] has been used. Additional operating costs have been obtained from Grigsby *et al.*[6]

The average current refining costs for gasoline and distillate oils are about 7¢-14¢/gal. The cost of liquefying hydrogen has been obtained from the data of Johnson.[9]

Table 8-1. COMPARISON OF FUEL-SYSTEM ECONOMICS (Ex-vehicle) FOR PRELIMINARY COSTS OF POSSIBLE ALTERNATIVE FUELS (1973 Dollars)

Resource Base, Synthetic Fuel	Resource Extraction and Fuel Synthesis	Refining or Processing	Transmission and Distribution	Total Cost
	$/10^6 Btu			
Coal				
Gasoline	0.95-1.25	0.75-0.85	1.00-1.20	2.70-3.30
Distillate Oils	0.95-1.25	0.40-0.50	1.00-1.20	2.35-2.95
Methanol	1.40-1.60	--	2.00-2.40	3.40-4.00
Methane (SNG)	0.95-1.50	--	1.60-1.80	2.55-3.30
Liquid SNG	0.95-1.50	0.85-0.95 (liq)	1.90-1.65	3.20-4.10
Hydrogen Gas	1.20-1.90	--	4.80-5.40	6.00-7.30
Liquid Hydrogen	1.20-1.90	1.60-1.80 (liq)	2.10-2.50	4.90-6.20
Hydrogen Hydride	1.20-1.90	Hydride at distribution	3.40-3.75	4.60-5.65
Synthetic LPG	0.95-1.25	0.85-1.00	1.35-1.60	3.15-3.85
Oil Shale				
Gasoline	0.70-1.00	0.95-1.05	1.00-1.20	2.65-3.25
Distillate Oils	0.70-1.00	0.50-0.60	1.00-1.20	2.20-2.80
Methane (SNG)	1.15-1.60	--	1.60-1.30	2.75-3.40
Liquid SNG	1.15-1.60	0.85-0.95 (liq)	1.90-1.65	3.40-4.20
Synthetic LPG	0.70-1.00	1.05-1.20	1.35-1.60	3.10-3.80
Nuclear Energy (Water)				
Electrolytic Hydrogen Gas	3.20-3.80	--	4.80-5.40	8.00-9.20
Liquid Hydrogen	3.20-3.80	1.60-1.80 (liq)	2.10-2.50	6.90-8.10
Hydrogen Hydride	3.20-3.80	Hydride at distribution	3.40-3.75	6.60-7.55
Thermochemical Hydrogen Gas	1.75-2.25	--	4.80-5.40	6.55-7.65
Liquid Hydrogen	1.75-2.25	1.60-1.80 (liq)	2.10-2.50	5.45-6.55
Hydrogen Hydride	1.75-2.25	Hydride at distribution	3.40-3.75	5.10-6.00
Solar Energy (Agriculture)				
Ethanol (190 proof)	7.25-17.50	--	1.50-1.80	8.75-19.30
$1.00-$3.00/bu wheat, 200 proof	7.25-17.50	0.25-0.35	1.50-1.80	9.00-19.65
	6.50-10.80	--	1.50-1.80	8.00-12.60
$1.00-$2.00/bu corn, 200 proof	6.50-10.80	0.25-0.35	1.50-1.80	8.25-12.95
Methanol $1.15-$1.40/10^6 bu pulpwood chips	2.30-2.65	0.20-0.30	2.00-2.40	4.50-5.35

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8.2 Fuel Transmission and Distribution Costs (Preliminary)

The cost of transporting these products between the refinery and final consumer outlet and handling them depend on the volume handled, the distance from the refinery to the consumer outlet, and the mode of transportation (pipeline, railroad tank car, or tank truck).

The resource bases of coal and oil shale are located predominantly in the Western U.S. The synthesis plants for syncrude, SNG, methanol, and other products will be in this region also. The major processing and market areas lie in the Midwest and along both coasts. Therefore, the output from these plants will have to be shipped from 600 to 1800 miles to reach the major consuming centers. (See Figure 8-1.)

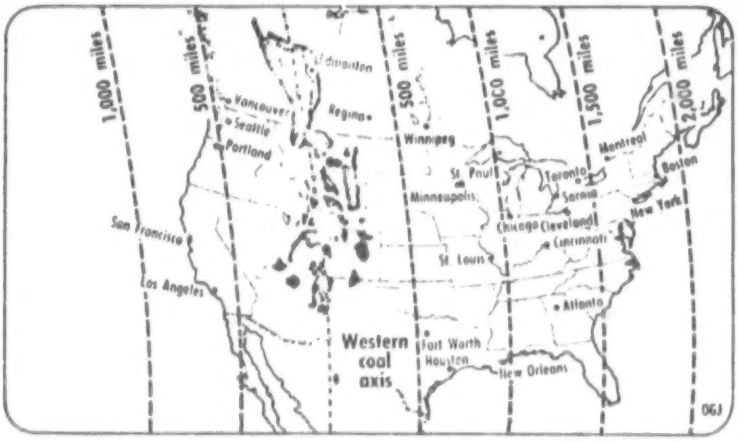
1,000 miles
500 miles
500 miles
1,000 miles
1,500 miles
2,000 miles
Edmonton
Vancouver
Seattle
Portland
Regina
Winnipeg
St. Paul
Minneapolis
Montreal
Toronto
Sarnia
Boston
New York
San Francisco
Chicago
Cleveland
Cincinnati
St. Louis
Los Angeles
Atlanta
Western coal axis
Fort Worth
Houston
New Orleans
OGJ

Figure 8-1. DISTANCES TO MAJOR COAL MARKETS (Source: Ref. 31)*

The major product pipeline costs from $300 to $800/bbl-calendar day (cd) of capacity. Figures published by the Explorer Pipeline Co. for its 28 and 26-inch lines from the Gulf Coast to Chicago are $550/bbl- d. Terminal capital requirements depend on size, but fall in a range of $100-$200/bbl. Tank trucks of 8500-gal capacity cost approximately $40,000 and can deliver 10 million gal/yr. Their capital requirements are estimated to be $60/bbl-cd of capacity.

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Service-station capital investment depends on the site, capacity, type of service, and other factors. The capital investment ranges from $2000 to $8000/bbl-day. A 50,000 gal/month sales volume per unit would require a base investment of approximately $160,000, using an average of $4,000/bbl-day capital requirement.

Liquid fuels such as methanol and ethanol would be transported, stored, and handled in a manner similar to that for gasoline and diesel fuel. Therefore, the cost estimates for marketing the latter have been used; adjustments have been made for the volumes needed to deliver the same energy requirements.

IGT has estimated the transmission costs associated with hydrogen in its report A Hydrogen-Energy System,[5] published by the American Gas Association. A summary is shown in Table 8-2.

Table 8-2. HYDROGEN TRANSMISSION COST

Pipeline Diameter, in.	Natural Gas (100 miles)	Hydrogen (65 miles)	Hydrogen (extrapolation) (100 miles)
		¢/10^6 Btu	
30	~1.14	2.05	3.15
36	~1.00	1.16	2.71
42	~0.91	1.54	2.37

The costs of transporting natural gas and crude oil have been calculated from data in the 1970 National Power Survey, Part III.[4] The source data are shown in Table 8-3. Shipping costs for liquid chemicals (fuels) were based on those in a recent article in Chemical Week.[33]

We have assumed that SNG could be transported to service stations through the present intracity distribution system (pipelines). The service-station modifications would involve the installation of a compressor, piping, meters, and a connecting nozzle for feeding methane into the car. Dual Fuel Systems[3] of Los Angeles has estimated the capital cost for service-station modifications at $20,000. The electricity cost is estimated at 1¢/100 CF for the compressor. This system will allow the station to have the quick-fill capability that would require approximately 5 minutes to service a car.

Table 8-3. DATA FOR PRELIMINARY COSTS OF FUEL TRANSPORTATION (Source: Ref. 4)

Form of Energy	Means of Transportation	Transportation cost per 100 miles	
		¢/Million Btu	Mills/Kwhr
Oil	Tanker ship	0.1 to 0.5	0.01 to 0.05
	Pipeline	0.04 to 1.6	0.04 to 0.16
	Barge (average)	0.5	0.05
	Railroad tank car (average)	4.3	0.43
	Truck (average)	7.4	0.74
Natural gas (gas)	Pipeline	1.1 to 1.4	0.11 to 0.24
Natural Gas (liquefied)	Tanker	0.5 to 0.9	0.05 to 0.09
	Barge	0.6	0.06
	Railroad	2.7	0.27

Total compression and service costs would depend on the volume of gas sold and the type of installation. Dual Fuel Systems[3] has estimated an average cost for compressing natural gas at 7¢-9¢/100 CF for fleet users.

8.3 Fuel Utilization Costs

As with environmental effects, costs at the station-vehicle interface are only part of the system. A complete fuel selection criterion is based on the cost per mile driven by the consumer. Calculation of this cost entails fuel-engine efficiency, vehicle weights, and vehicle fuel tankage costs, as well as the fuel cost at the service station-vehicle interface. We have found that considerable effort is required for these estimates and calculations because they involve a mix of measured, approximated, and assumed values. The conclusions drawn from these calculations have not been used in the fuel selection procedure.

The details of these calculations are beyond the scope of this report. In summary, using EPA-reported efficiencies, an EPA mileage-versus-weight correlation, and our estimates of vehicle weights and efficiencies with unconventional power plants, we have obtained the cost-per-mile estimates shown in Table 8-4. Regardless of engine type and ignoring differences in engine costs, four important conclusions result:

1. Agricultural ethanol costs about 3 times as much as the other candidate fuels (except hydrogen); this conclusion also is indicated by the first-tier costs in Table 8-1.

2. Although hydrogen in Table 8-1 is about 3 times as expensive as the other candidate fuels (except ethanol), it is only about 2 times as expensive in cost per mile (Table 8-4). Further, liquid hydrogen is cheaper than a metal hydride (e.g., Mg_2NiH_x, a lightweight hydride), and this is not shown by the preliminary costs in Table 8-1.

3. LSNG costs more than methanol, as shown in Table 8-4, but it costs less than hydrogen.

4. Operation on distillate fuels from coal or oil shale (particularly the diesel) is decidedly the cheapest fuel system.

Table 8-4. ESTIMATED CONSUMER COSTS FOR ALTERNATIVE FUELS IN VEHICLES WITH VARIOUS POWER PLANTS
(Based on Preliminary Costs From Table 8-1)

Fuel	Conventional*	Open-Chamber Stratified-Charge	Dual-Chamber Stratified-Charge	Diesel	Brayton	Rankine	Stirling
	¢/mile						
Distillate Oils	-- --	2.44 ± 0.53	--	1.91 ± 0.52	2.53 ± 0.74	2.76 ± 0.82	2.50 ± 0.52
Ethanol	14.70 ± 5.92 W 9.97 ± 3.00 P	9.97 ± 3.37	10.09 ± 3.49		10.36 ± 4.21	11.28 ± 4.53	9.42 ± 4.17
Gasoline	4.68 ± 1.36 W 3.40 ± 0.75 P	2.90 ± 0.61	3.04 ± 0.68	--	3.00 ± 0.85	3.27 ± 0.88	2.71 ± 0.85
Hydrogen (Liquid)	6.57 ± 3.14 W 5.15 ± 2.06 P	5.13 ± 2.00	--	4.77 ± 2.03	6.80 ± 2.83	7.39 ± 2.98	5.98 ± 2.69
Hydrogen (Hydride)	7.52 ± 3.42 W 5.82 ± 2.33 P	5.84 ± 2.39	--	5.22 ± 1.72	7.96 ± 3.36	8.39 ± 3.47	7.05 ± 3.14
Methanol	4.05 ± 1.05 W 2.96 ± 0.56 P	2.86 ± 0.52	2.99 ± 0.59	--	3.36 ± 0.84	3.59 ± 0.86	3.01 ± 0.85
LSNG	5.21 ± 1.72 W 3.82 ± 0.97 P	3.63 ± 0.88	3.64 ± 0.95	--	3.89 ± 0.95	4.02 ± 1.18	3.69 ± 0.82

[*] W = Wankel; P = Piston.

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8.4 Costs of Resource Extraction and Fuel Synthesis (Candidate Fuels)

On the basis of workable processes and available engineering and economic data, we selected example or pattern processes for synthesis of alternative fuels. These processes are not necessarily recommended for commercialization. Appendix B contains detailed process descriptions and economic calculations. These pattern processes are well developed technically or are composed of process components for which sufficient data have been published to allow characterization and reasonable estimates of economics. The economics have been calculated by using the DCF financing method discussed in the FPC's report on synthetic gas-coal.[a]

Based on process equipment requirements and operating (or experimental) data, we have made careful determinations of all components of capital and operating costs. The method is outlined in Tables 8-5 and 8-6, and the calculations are included in Appendix B. Table 8-7 presents the results for those candidate fuels and synthesis routes that can be characterized in sufficient detail. The processes described are "pattern" processes for fuel synthesis, and certain other synthesis processes would be equally (or more) acceptable for commercialization. The synthesized fuels are candidates for use as alternative fuels for automotive transportation, but they are not necessarily the selected (chosen or recommended) alternatives. The selected fuels depend on the needs for supplemental fuel, as shown by an energy demand and supply projection, and on the application of a fuel selection procedure, as described in Section 2.

During this study, the domestic petroleum reference base underwent a major change in economics. The reference gasoline cost to be compared with preliminary costs of potential fuels was set at $2.40/million Btu (lower heating value): $1.20 for resource extraction and refining and $1.20 for transmission and distribution. This cost for reference gasoline was valid during the first half of 1973. However, it does not correspond rigorously, in all cases, to the preliminary costs of alternative fuel systems (Table 8-1), because capital and other costs for these systems were taken from literature published prior to 1973 (generally in the late 1960's and early 1970's). Although appropriate cost escalation factors were used, these preliminary costs are of doubtful accuracy in absolute terms. However, we consider them acceptable for intercomparisons and preliminary evaluations.

Table 8-5. BASIS FOR CALCULATING GROSS AND NET OPERATING COSTS FOR PRODUCING CANDIDATE FUELS

Raw Materials	
Mine-Mouth Coal ($0.30/$10^6$ Btu)	XXX
Oil Shale at Mine ($0.86/ton)	XXX
Catalysts and Chemicals	XXX
Purchased Utilities	
Electric Power ($0. 009/kWhr)	XXX
Raw Water ($0. 30/1000 gal)	XXX
Natural Gas ($1. 00 /1000 SCF)	XXX
Labor	
Process Operating Labor (men/shift X 8304 man-hours/year X $/man-hour)	XXX
Maintenance Labor (1. 5%/yr of total plant investment)	XXX
Supervision (15% of operating and maintenance labor)	XXX
Administration and General Overhead (60% of total labor, including supervision)	XXX
Supplies	
Operating (30% of process operating labor)	XXX
Maintenance (1. 5%/yr of total plant investment)	XXX
Local Taxes and Insurance (2. 7%/yr of total plant investment)	XXX
Total Gross Operating Cost (per year)	XXX
By-product Credits	(XXX)
Total Net Operating Cost (per year)	XXX

Table 8-6. BASIS FOR FUEL COST CALCULATION BY THE DCF METHOD*

Basis

- 25-year project life
- 16-year sum-of-the-years'-digits depreciation on total plant investment
- 100% equity capital

Essential Input Parameters

- 12% DCF return rate
- 48% Federal income tax rate

Handling of Principal Cost Items

- Total plant investment and working capital are treated as capital costs at start-up completion.
- "Return on investment during construction" (equal to total plant investment X DCF return rate X 1.875 years) is treated as a capital cost at start-up completion.
- Start-up costs are treated as an expense at start-up completion.

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* See Appendix B (Volume III) for detailed calculations.

Table 8-7. PATTERN SYNTHESIS PROCESSES AND FUEL PRODUCTION COSTS (For 1973 in 1973 Dollars)

Raw Material	Synthesized Fuel	Pattern Process	Production Cost (12% DCF)* Volume Basis, \$/gal	Production Cost (12% DCF)* Energy Basis, \$/10^6 Btu*
Coal	Gasoline	Consol Synthetic Fuel (CSF) plus refining with hydrocracking	0.33	2.81
Coal	Gasoline and distillate oils	Consol Synthetic Fuel (CSF) plus refining with catalytic cracking	0.31	2.51
Oil Shale	Gasoline and distillate oils	Gas Combustion Process (Bureau of Mines) plus hydrotreating and refining	0.25	2.05
Coal	Methanol	Koppers-Totzek gasifier and ICI synthesis	0.23	3.88
Coal	SNG (CH_4)	Lurgi gasifier with methanation	1.84/10^3 SCF†	2.14

* If 10% SCF financing is used, the resulting fuel synthesis costs are 88% to 91% of the costs presented in this table.

† Basis: the low heating value of the fuel.

To correspond with up-to-date economics for the candidate fuels selected and studied several months later, the reference gasoline cost was updated (for accuracy and validity of comparison) to \$2.80/million Btu (lower heating value). This was \$1.60 for resource extraction and refining, and \$1.20 for transmission and distribution (December 1973). Use of these reference fuel costs (adjusted for time frame) is demonstrated in Section 10 in the selection of candidate fuels.

A candidate fuel and synthesis procedure of interest for the far term is hydrogen produced thermochemically from water. Thermochemical production is designed to decompose water into hydrogen and oxygen by using the heat energy available from nuclear reactors. The process concept is described in Section 5. At present, no commercial process for the thermal conversion of water to hydrogen and oxygen exists. Nevertheless, many proposed multistep chemical reaction sequences, in theory, could thermally separate water at lower overall temperatures (less than 1000°C). IGT has obtained experimental evidence for proof of concept and information[16] on practically attainable energy efficiencies. Currently, work is being conducted in the laboratory to identify the chemical reaction cycles that appear to have the greatest potential. To date, most research has been directed at the range of heat input temperature between 700° and 1000°C. The respective energy transfer efficiencies reported fall between 40 and 60%. Despite the many uncertainties associated with evaluating this infant technology, its long-term potential is too great for it to be excluded from this study, especially after the year 2000.

For this analysis, a nuclear heat-to-hydrogen energy conversion efficiency of 50% is used. This is a reasonable estimate, and the economics associated with this process are very sensitive to this number. A 1% change in efficiency is equivalent to 12¢/million Btu of hydrogen produced over the life of the project. The HTGR reactor was assumed to be the primary heat source because it is potentially capable of achieving temperatures of 1000°C and because its operating and economic characteristics are reasonably well-known.

8.4.1 Nuclear Reactor Heat Cost Analysis

During 1973, plans for 38 new nuclear plants were announced, and the capital costs ranged from $313,000 to $650,000/MWe, with an average cost of $456,000/MWe. The scheduled construction periods were between 6 and 13 years, with an average of 8.8 years. The capital costs for the nuclear heat module of a thermochemical plant were estimated from capital costs reported in Combustion.[17] Both estimates appear in Table 8-8.

In determining the reactor operating cost, two primary source documents were used.[23,24] The cost components reported in Combustion[23] were derived by the EEI Reactor Assessment Panel. The totals from both sources were in reasonable agreement; i.e., 1.74-1.82 mills/kWhr was projected for 1975.

Table 8-8. NUCLEAR HEAT MODULE COSTS FOR A THERMOCHEMICAL HYDROGEN PLANT

Cost Component	Nuclear Electric $1000/MWe	Nuclear Thermochemical[*] $1000/MWe
Nuclear Steam Supply System	46	46
Turbine Generator Unit	33	
Construction Materials and Equipment	72	50
Craft Labor	85	60
Professional Services	42	30
Construction Management	26	18
Contingencies	14	10
Plant Investment	318	214

[*] Two modules of this size are required for a nominal 250 X 10^9 Btu/day hydrogen plant.

There were significant variances in the individual cost components, primarily mining and milling, and enrichment. In these instances, the EEI values were selected because they were more in agreement with the operating characteristics of an HTGR reactor as reported[27] by the AEC.[*] The cost components used in this study are as follows:

	mills/kWhr
Mining and Milling ($8/lb U_3O_8)	0.56
Enrichment ($26/SWU[†])	0.62
Fabrication	0.34
Shipping and Reprocessing ($45/kg of uranium)	0.19
Waste Management	0.04
Plutonium and Uranium Credit ($7.50/gram of plutonium)	−0.35
Total	1.40

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[*] This source does not reflect the thorium requirements. In terms of thorium oxide, these quantities represent nearly 10% of the initial and annual uranium oxide requirements. Also, thorium oxide and uranium oxide unit costs are comparable.

[†] SWU = Separative work unit.

The total operating cost used in this study is as follows:

	mills/kWhr
Fuel Costs	1.40
Operations and Maintenance	0.30*
Insurance	0.10*
Supplies and Taxes	0.15*
Total	1.95

* Source: Ref. 5

To arrive at an annual operating cost, a plant availability factor of 0.9* and a plant capacity factor of 1 were used. The actual annual operating charge calculated was $15.4 million/yr.

Currently, most economic analyses of reactors are based on heat output in terms of electrical energy equivalent. HTGR heat can be converted to electricity at an efficiency of approximately 39%. A standard 1160-MWe reactor requires a net thermal output of 2974 MWth, which is available for thermochemical hydrogen production. Assuming a reactor availability factor of 0.9 and a capacity factor of 1.0, the heat generated in the reactor is 68.99 trillion Btu/yr. When these cost and energy output data are subjected to the standard DCF calculations, a price for unit heat transfer between the reactor and the thermochemical processing plant of $2.01 /million Btu was obtained. In the DCF calculations, an optimistic construction period of 3.5 years was assumed for consistency and to acknowledge the shorter construction periods commensurate with industry growth in the future.

8.4.2 Thermochemical Plant Cost Analysis

We acknowledge that it is presumptious to estimate the cost associated with the processing plant without specifying the particular thermochemical cycles. However, commercially attractive multistep chemical reaction cycles will have several important things in common. These cycles will be closed-loop regenerative processes. For a given heat supply, efficiencies of practical cycles should be within 10% of each other, and therefore, hydrogen production capacities should not vary significantly. At this stage of development, common chemicals are being considered and only very small makeup quantities will be required after the initial loading. Therefore, the use of the chemicals should not be a critical factor. Unless a major breakthrough makes them advantageous, exotic chemical processing schemes will not be required.

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* This figure is high by nearly 10% when compared with plant availability factors quoted by the AEC. Also, it is approximately 20% higher than past experience indicates. Nevertheless, technology improvements are anticipated prior to the period when these plants are scheduled to be placed on-stream and all other fuel conversion processes are compared on this basis.

The estimated capital costs associated with a general thermochemical plant (chemical sequence unspecified) are shown in Table 8-9. These costs are educated guesses projected from laboratory-scale studies.

Table 8-9. THERMOCHEMICAL PLANT CAPITAL COSTS
(1973 Dollars; 250 X 10^9 Btu/Day Hydrogen)

Cost Components	Cost, $\$10^6$
Chemical Process Reactor System	75
Gas Separation System	25
Gas Compression	5
Heat Recovery System	25
Oxygen Compression and Storage	10
Raw Water Storage, Treatment, and Pumping	15
Initial Catalysts and Chemicals	20
General Facilities	40
Contractor Fees	30
Contingencies	30
Total Plant Investment	275

Table 8-10 depicts the operating cost components used in this analysis.

Table 8-10. THERMOCHEMICAL PLANT OPERATING COST
(1973 Dollars; 250 X 10^9 Btu/Day Hydrogen)

Cost Components	Annual Cost, $\$10^6$
Purchased Raw Materials	
Heat (164.25 X 10^9 Btu/yr, $\$2.01/10^6$ Btu)	330.04
Water (18,500 gpm, \$0.30/1000 gal)	2.62
Catalysts and Chemicals	5.00
Labor	
Process Operating Labor (62 men/shift, \$5/hr, 8304 man-hr/yr)	2.57
Maintenance Labor (1.5% of plant investment)	4.12
Supervision (15% of operating and maintenance labor)	1.00
Administration and General Overhead (60% of total labor, including supervision)	4.61
Other Charges	
Supplies (30% of process operating labor)	0.77
Maintenance (1.5% of plant investment)	4.12
Local Taxes and Insurance (2.7% of plant investment)	7.42
Total Gross Operating Costs	362.27
By-product Credit	
Oxygen (126.47 X 10^9 CF/yr, \$7/ton)	39.46
Net Operating Cost	322.81

When these estimated capital and operating costs are factored into the standard DCF calculations, the basic cost of producing hydrogen is $\$4.80/10^6$ Btu. This cost includes a by-product credit for the oxygen produced, but it does not consider a by-product credit for the heat not used. A process heat supply at 1600°F with a 700°F temperature drop is assumed to drive the chemical reaction cycle. Thus, the equivalent of 34.5 X 10^{12} Btu/yr at temperatures of 900°-200°F is not being utilized. This heat source is adequate to drive a nominal 400-MWe turbine generator unit. A credit of 10 mills/kWhr produces revenues of \$32.3 million/yr.

The capital cost associated with the turbine generator unit is estimated at $40 million (from Table 8-8 scaled to 400 MWe). The associated operating cost is estimated at $4.75 million/yr. The revenue needed to regain this cost over the life of the project is $15 million/yr. The net saving is $17.3 million/yr. This yearly saving reduces the cost of hydrogen produced to $4.55 /$10^6$ Btu. This cost in 1973 dollars with energy by-product credits is consistent with the costs of other fuels (from oil shale or coal) with their by-product credits (per Table 8-7)

8.5 Costs of Transmission and Distribution (Candidate Fuels)

For candidate gaseous fuels, the preliminary estimates are derived from the best available data, and no further refinements have been necessary or attempted. The natural gas pipeline network furnishes adequate logistics information and operating data. Separate IGT studies on hydrogen transmission are sufficiently extensive for complete economic estimates, and these were included in the preliminary costs. The preliminary service-station costs for potential fuels are also adequate for comparisons among the candidate fuels.

Because the transport of liquid hydrocarbons from the Rocky Mountain area constitutes new logistics for the energy supply, we have made further and more detailed cost estimates of the long-distance transport of shale oil or syncrude from coal to existing refining and marketing centers. The results do not substantially change the previous (preliminary) costs; details are summarized below.

We have carefully estimated the economics associated with oil pipelines from the Green River region in Wyoming. We assume that these pipelines would go to Houston, Chicago, and Los Angeles. The basic parameters of the analysis are as follows:

- Volume: 100,000 bbl/day.
- Syncrude specifications: 46.2° API; specific gravity, 0.796; and viscosity, 40 SSU (100°F).
- Maximum pressure was not established specifically, but a maximum operating pressure of around 1200 psi was set as desirable.

The remaining parameters of pipe diameter, horsepower, and operating characteristics are contingent on the above and on the pipeline route.

The routes for the three destinations are stated in Table 8-11 with intermediate cities and gross changes in altitude.

Table 8-11. ASSUMED SYNCRUDE PIPELINE ROUTES

Pipeline	City	Average Estimated Altitude, ft	Distance From Last Point, miles
Green River to Houston	Green River, Wyo.	8000	--
	Cheyenne, Wyo.	5000	275
	Amarillo, Texas	2500	520
	Vernon, Texas	1150	175
	Fort Worth	300	155
	Houston	300	285
			1410
Green River to Chicago	Green River, Wyo.	8000	--
	Cheyenne, Wyo.	5000	275
	North Platt, Neb.	2500	205
	Lincoln, Neb.	1150	215
	Chicago	300	530
			1225
Green River to Los Angeles	Green River, Wyo.	8000	--
	Las Vegas, Nev.	1150	500
	Los Angeles	1150	410
			910

On the basis of the pipeline route, the volume to be moved, and product specifications, the associated hydraulics can be calculated and the pipeline diameters and horsepower requirements chosen. We have estimated the approximate locations of pumping stations and the necessary pump horsepower requirements for a 20-inch-diameter pipeline.[20]

The horsepower requirements are very low: 3300 hp for the Houston pipeline, 2305 hp for Chicago, and 850 hp for Los Angeles. This is the case because of the very high static head due to the large negative change in altitude, and the relatively low function head associated with a 20-inch line for this thoughput. All the pipelines are assumed to begin with a pumping station. The Houston and Chicago pipelines each have one additional pumping station,whereas the Los Angeles line needs only the initial one.

Estimates of the investment components are shown in Table 8-12. The gross investment, exclusive of product inventory in the pipeline and storage, is about $5500/in. /mile for the 20-inch-diameter lines. Inventory costs are based on the total volume of syncrude necessary to fill the pipelines and the initial storage fill. The price of syncrude has been set at $10/barrel for this initial estimate.

Table 8-12. ESTIMATED INVESTMENT (1973 Costs) FOR SYNCRUDE PIPELINE[15, 32]

	Houston	Chicago	Los Angeles
Miles of Pipeline	1410	1225	910
Number of Pump Stations	2	2	1
Total Horsepower	3300	2305	850
Investment		$ million	
Right of Way and Damages	5.58	4.85	3.60
Survey and Mapping	0.82	0.71	0.53
Line Pipe	73.08	63.49	47.17
Coating and Wrapping	2.97	2.58	1.92
Freight	4.76	4.14	3.08
Sales Tax	2.19	1.90	1.42
Cathodic Protection	0.67	0.58	0.43
Construction	40.95	35.57	26.43
Pump Stations	0.46	0.36	0.15
Storage	2.60	2.60	2.60
Capital Equipment Cost	134.08	116.78	87.33
Engineering, Inspection, and Testing (2%)	2.68	2.34	1.75
Contingencies and Overhead (5%)	6.70	5.84	4.37
Capitalized Interest During Construction (9%)	12.07	10.51	7.86
Pipeline and Storage Inventory	37.94	34.27	28.03
Total Investment	193.47	169.74	129.34

Operating costs are estimated in Table 8-13. Included in the variable operating costs are maintenance, cathodic protection, labor, supplies, communications (which for our purposes have been assumed to be leased), power costs to the pumps, overhead charges for administrative costs, buildings, and miscellaneous salary, travel allowances, and product loss contingencies.

Table 8-13. OPERATING COSTS FOR SYNCRUDE PIPELINE[32]

	Houston	Chicago	Los Angeles
Miles of Pipeline	1410	1225	910
Number of Pump Stations	2	1	2
Total Horsepower	3300	2305	850
	$ million		
Fixed Operating Costs	25.98	22.80	17.37
Variable Operating Costs			
Maintenance			
Pipeline	0.34	0.29	0.22
Stations	--	--	--
Storage	0.03	0.03	0.03
Cathodic Protection			
Pipeline	0.01	0.01	0.01
Stations	--	--	--
Supplies			
Delivery Facilities and Stations	0.01	0.01	0.01
Communications	0.14	0.12	0.10
Labor	0.40	0.36	0.40
Power	0.46	0.32	0.12
Overhead and Miscellaneous Contingencies	0.14	0.11	0.09
Total Annual Operating Costs	27.51	24.05	18.35

The fixed charge rate is calculated to be 13.4% by using the minimum revenue requirement discipline (MRRD).[8] This method includes revenue requirements only and makes no assumptions about profit incentive. Assumptions made for calculating the fixed charge rate are –

- 90% debt/10% equity
- 9% interest rate on debt
- 12% return on investment
- 25-year project life
- Zero salvage value
- Straight-line depreciation for accounting
- Sum-of-year-digits depreciation for tax purposes.

In principle, then, MRRD calculates the cost-of-service of moving syncrude through a pipeline from A to B. Unit costs are 5.35¢-5.52¢/bbl/100 miles, as shown in Table 8-14.

Table 8-14. UNIT COST OF SYNCRUDE PIPELINE

	Houston	Chicago	Los Angeles
Miles of Pipeline	1410	1225	910
Total Annual Operating Cost, $\$10^6$	27.51	24.05	18.35
Unit Operating Costs			
¢/bbl/100 miles	5.35	5.38	5.52
¢/bbl	75.4	65.9	50.3

Table 8-15 summarizes the candidate fuel transmission and distribution costs with conservative 1400-mile transmission and 150-200 mile distribution distances.

8.6 Candidate Fuel System Costs (1973)

Table 8-16 presents the system costs for the candidate fuels, exclusive of vehicle utilization, in terms of late-1973 dollars. They are the predicted fuel costs at the service station-vehicle interface, but do not include Federal and state sales and other taxes normally imposed on gasoline.

In the future, the real costs of coal, oil shale, and fissile (nuclear) fuels will escalate because of such factors as the necessity for deeper mining, the use of lower-assay-material deposits, and longer distance transport of materials including water. Synthesis costs also will escalate because of the necessarily increased amounts of processing per unit of product.

8.7 Analysis of Future Real Costs (Noninflationary) of Candidate Fuels

Fuel production costs cannot be analyzed and projected without considering two related factors: 1) alternative fuel system objectives and project life and 2) the role of future prices in supply and demand. The cost analysis discussed in this section is based upon certain premises of study objectives and future prices. These premises are explicitly stated below to establish a frame of reference for the comparative cost analysis of candidate fuel production in future time frames.

Table 8-15. SUMMARY OF TRANSPORTATION COSTS FOR CANDIDATE FUELS

Fuel and Resource	Field-to-Refinery Cost	Product Distribution Cost	Terminal Charge	Truck-to-Service Station Cost	Service Station		Liquefaction or Hydride	Total
					Cost[*]	Capital Recovery (Rent) at 2¢/gal		
	$¢/10^6$ Btu							
Gasoline From Shale and Coal	9.14 (1400 miles)	2.14 (150 miles)	1.63	6.94	68.56	17.1	--	106
Methanol From Coal	18.66 (1400 miles)	4.15 (150 miles)	3.16	13.43	68.56	25.7	--	134
Liquid SNG From Coal	22.40 (1400 miles)	6.0 (150 miles	3.16	15.4	68.56	34.2	54.1	204
Liquid Hydrogen From Coal	52.2 (1400 miles as gas)	21.8 (150 miles)	16.3	49.7	68.56	34.2	140.4	383
Hydrogen (Hydride) From Coal	52.2 (1400 miles as gas)	29.0 (200 miles)	--	--	68.56	25.7	45.0	221

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[*] This charge is assumed to be independent of the fuel volumetric heating value and the equipment costs.

Table 8-16. SYSTEM BASE COSTS FOR CANDIDATE FUELS (Late 1973)[a]

Resource Base and Synthetic Fuel	Resource Extraction and Fuel Synthesis	Transmission and Distribution	Total Cost	Total Cost,
	$/10^6 Btu			$/gal
Coal				
Gasoline (Primarily)	2.81	1.06	3.87	0.49
Gasoline and Distillate Oil[b]	2.51	1.06	3.57	0.47
Methanol	3.88	1.34	5.22	0.32
SNG[c]	2.14	2.04	4.18	0.31
Oil Shale				
Gasoline and Distillate Oil[b]	2.05	1.06	3.11	0.39
Nuclear Heat				
Hydrogen[d]	4.55	3.83	8.38	0.25
Hydrogen[e]	4.55	2.21	6.76	--
Reference Gasoline	1.60	1.20	2.80	0.33

[a] Basis, low heating values of the fuels.

[b] 50:50 product mix, average price.

[c] SNG transmission and distribution as a gas, liquefied at service stations.

[d] Thermochemical hydrogen transmission to terminal as a gas, liquefied, and distributed in liquid-hydrogen trucks to service stations.

[e] Thermochemical hydrogen transmission and distribution as a gas, combined as a metal hydride at the service stations.

8.7.1 Objectives and Project Life

A global objective of this feasibility study is to satisfy future automotive energy demand patterns based upon an extrapolation of historical demand patterns and to assess the feasibility of the U.S. becoming as domestically self-sufficient as possible without incurring excessive costs. Emphasis was placed on ensuring the supply of an existing automotive fuel (gasoline or an acceptable substitute or supplement) without significant economic dislocations.

The initial approach was to determine the cost and the potential availability of fuels derived from domestic resources. The second phase involved collecting detailed data on new technology for producing acceptable fuels from selected energy sources. The candidate fuels were compared on the basis of cost by an analysis of capital budgeting.

A prime requisite for the comparison of capital budgeting programs is the length of the planning horizon, or the project life, particularly when alternatives involve programs with different project lives that can start at different times.

For this study, all potential alternative fuel programs were evaluated for a minimum project life of 25 years, although there is no firm justification for this particular period. Industrial practice varies between 5 and 30 years. In the chemical industry, there is a high substitution rate among products, and the new products that are frequently introduced are not conducive to long-term planning horizons. The utility industries represent the major group over 20 years. This utility industry practice originated with early institutional guidelines requiring all new projects to have a minimum life of 20 years.

Conceptually, a project has three lives: a physical life, a technological life, and a production, or market, life. Ideally, the shortest of these life cycles is selected as the base period for comparison. In this study, an objective is to assess the availability of an existing fuel or an acceptable substitute in time frames extending beyond the year 2000. For the most part, only the newest technology was considered; therefore, the shortest life cycle appears to be the physical life. Some of the equipment in the reprentative fuel conversion processes will not last 25 years; however, much of the plants, facilities, and equipment will last this long.

For this study, several additional factors must be considered to establish program life. An important consideration is that we are dealing with fixed resource bases (e.g., oil shale, coal, or uranium deposits) for each project. Because of location and technology, a fuel conversion process is usually coupled to a single raw material supply. In commercial practice, this raw material supply is selected because it has the potential for 30-40 years of supply. This makes an extended program life more economically attractive. Another important consideration is the manner in which these programs must be financed. The development of a new synthetic fuel industry will be very capital-intensive, 3-4 times more than the present-day petroleum or petrochemical industry. The probability is very small that all the required capital can be generated internally from industry funds within the necessary time span. Therefore, the general trend will be toward debt financing by using the vehicle of 20-30 year bonds. Again, this trend enhances the use of an extended program life. For these reasons, we have chosen 25 years as the average project life for evaluation purposes.

8.7.2 Future Prices

In this analysis, price is viewed as the mechanism for balancing the flow of funds over the project planning horizon. In general, the accomplishment of the same project objective in a shorter time frame requires higher prices to accumulate the same amount of funds. Conversely, a project with identical costs, evaluated over a longer project life, requires a lower price to accumulate similar funds. The relationship between supply and demand is assumed to be constant over the life of the project, and the price equals the return on investment plus all associated costs over the life of the project. Two critical aspects of this analysis are a steady supply-demand relationship throughout the project life and the inclusion of all costs that will occur over the life of the project.

The probability of actually maintaining a continuous supply-demand equilibrium is low. Current plus projected demand already exceeds current plus projected supply, and no large-scale substitute automotive fuels have appeared on the planning horizon. Hence, an assumption of steady-state conditions would most likely be invalid. When steady-state conditions are disrupted in a free market, the incurred price increases until the supply-demand relationship regains equilibrium; either supply catches up to demand, or demand is reduced to equal supply. In this analysis, the return on investment is held constant, and the price increases reflect the minimum costs associated with increasing supply to the point that it again equals demand.

The cost analysis includes all costs that must be incurred over the life of the project. The capital and operating costs that we have considered are associated with the accumulation and use of the natural resources that are raw materials for fuel production. Generally, these resources are limited, irreplaceable commodities. The acquisition of these raw materials contains two principal cost components: exploration and production. The exploration cost component is associated with the precise location and amount of the basic raw commodity. The natural resource production cost component is associated with the extraction of the commodity from its natural state. Initial cost estimates for raw material production will not be correct unless adequate reserves are allocated and sufficiently defined over the life of the project. The probability for error occurs because the next unit of production will not cost the same as the last unit of production. Marginal economic analysis is not always applicable because the natural resource may be limited and irreplaceable. As the sum of past production approaches the upper limit of total availability, the cost associated with the acquisition of new incremental production increases beyond proportionality.

For a finite natural resource, increasing exploration costs will, at some time, produce less than proportional or normal results. For this reason, economic theory dictates that the return on investment should be adequate to generate the funds required to develop desirable substitute resources after the existing resource bases have been depleted. Obviously, supplemental or substitute resources are more expensive; otherwise, they would have been developed first. Hence, the development of supplemental resources reflects real cost increases.

In the cost analyses for candidate alternative fuels in future time frames, all the real cost increases are associated with the exploration and production of limited irreplaceable commodities and their synthesis into automotive fuels.

As a new synthetic fuel industry develops, some cost saving can result from technological improvements beyond those anticipated in this analysis. However, they will not be adequate to offset the cost increases resulting from the depletion of finite irreplaceable resources.

Also, economies of scale will not be realized beyond those already included. The basic plant size used in the technical and economic analyses (Appendix B) are well beyond the domain in which economies of scale could occur. Further, we have attempted to include all real cost components in this analysis, except for the costs of land reclamation, environmental impacts, legal aspects, and societal dislocations. We have quantified the costs required to develop new incremental production by using the accumulated historical or scheduled consumption as a reference.

8.7.3 Projections of Future Fuel Production Costs (Summary)

As stated previously, the projected future costs are based primarily on the real cost increases associated with obtaining new (incremental) fuel production from a limited resource base. The projected costs are f.o.b. plant. Transmission and distribution costs are not treated because they are considered about constant throughout the planning horizon. Technological improvements are incorporated in this analysis, but such improvements are offset by the real cost increases associated with the raw material resources. Table 8-17 reflects an overview of the real cost increases anticipated throughout the planning period.

Table 8-17. PROJECTION OF FUTURE FUEL PRODUCTION COSTS
(In 1973 dollars)

Period	Thermo-chemical Hydrogen	Coal to SNG	Coal to Gasoline	Oil Shale to Gasoline	Coal to Methanol	Reference Crude Oil to Gasoline
	$\$/10^6$ Btu					
1973 Base	4.55	2.14	2.51	2.05	3.88	1.60
Near Term (1985)	--	2.74	3.64	3.32	4.77	2.76
Mid Term (2000)	4.79	4.00	5.29	5.74	6.47	4.56
Far Term (2020)	4.79	4.60	6.16	6.97	7.36	7.82

Table 8-18. COMPARISON OF FUEL[a] PROCESSING SCHEMES
(Nominal Production: 250 Billion Btu/day; 1973 Base Data)

Processing Scheme	Capital Cost	Net Annual Operating Cost	Refinery Gate Price	Ratio of Feed to Operating Costs	bbl Water per 10^6 Btu Product
	$\$10^6$				
Crude to Gasoline and Distillate (50:50)	100[b]	140	1.60	0.86	0.3
Oil Shale to Gasoline and Distillate (50:50)	608[c]	54	2.05	0.50[e]	1.3
Coal to Gasoline and Distillate (50:50)	653[d]	92	2.51	0.66	1.1
Coal to Methanol	980[d]	136	3.88	0.49	1.8
Coal to SNG	496[d]	64	2.14	0.69	1.0
Thermochemical Hydrogen					
Nuclear Plant	428	15			
Thermochemical Processing	275	323			
Total	703	338	4.55	0.91[f]	2.5

[a] Low heating value.

[b] Based on a crude price of $6.96/bbl.

[c] Includes mining capital expenditures equivalent to $0.84/$10^6$ Btu.

[d] Based on a coal price of $0.30/$10^6$ Btu.

[e] Not listed as a separate item, estimated.

[f] At nuclear reactor-thermochemical plant interface.

These figures are not the average costs for the time frame in question; rather, they represent the costs of new incremental production at the end of the period.

An overview of some of the significant parameters associated with the candidate fuel systems, upon which these costs are based, is shown in Table 8-18. An analysis of the specific cost components associated with these respective future production costs is presented later in this section.

8.7.4 Future Domestic Crude Oil and Refinery Product Cost Analysis

As stated previously, we do not believe there will be significant real cost increases associated with the transmission distribution costs between the refinery gates and the service stations.

Table 8-19 reflects the results of the anticipated real cost increases in the areas of exploration, development, and production.

Table 8-19. FUTURE CRUDE OIL AND REFINERY GATE COSTS
(Domestic Crude Reference Base, 1973 $)

	Crude Oil (Input)			Refinery Gate (Product)	
Year	$/$10^6$ Btu	$/bbl	%/yr Growth	$/$10^6$ Btu	$/bbl
1973	1.20	6.96	8.25	1.60	9.04
1980	1.92	10.85	6.95	2.32	13.11
1990	2.80	15.82	3.84	3.20	18.08
2000	4.16	23.50	4.00	4.56	25.76
2010	6.16	34.80	4.00	6.56	37.06

Table 8-19 includes no increase for refinery costs but an overall increase of 4.52%/yr in crude oil costs. The constant refining cost is $0.40/bbl. Note that the basic oil cost used for 1973 was $6.96/bbl. A precise definition of this cost is necessary because there is a very real question of "What is the base price of crude oil for the U.S. in 1973?" Although much of the crude oil cost movement during 1973 was surrounded by political actions and it was a transitional year for crude oil cost worldwide, world crude production during 1973 nearly equaled world crude demand. In the U.S. production was only 70% of demand.

In January 1973, the average price of crude worldwide was $4.50/bbl. In December 1973, the average price of crude worldwide was $10.00/bbl, more than a 200% increase. During the last 3 months of 1973, crude oil was purchased for as much as $24/bbl. During this period, Governmental price controls were in effect. There was a two-tier crude oil pricing system in the U.S.: $5.25/bbl for old oil and $8.50 for new oil from stripper wells (15% of domestic production was from new oil). Further, 30% of our petroleum products were purchased from foreign markets at worldwide market prices. The weighted average of these data is $6.96/bbl.

The primary basis for crude-oil real cost increases is that much of the readily accessible geology has been explored, especially in the U.S. During the 1960's, approximately 7000 exploratory wells were drilled each year in the U.S. The sum of these yearly drillings was approximately 40 million ft/yr, excluding the 15,000-20,000 development wells per year. The net result of these extensive activities was an average annual addition to reserves of 3.6 billion bbl/yr. Assuming a modest reserve-to-production ratio of 10, this is equivalent to a production rate of 1 million bbl/day, or approximately 6% of present demand. Current production is being supported by additions to resources made prior to 1960. This situation is not unique, and similar statistics are reported in many other countries, including some major producing countries.

In the future, we will have to extend our exploration to the more inaccessible and/or more complex stratigraphy. The unit cost associated with exploration and development of more complex stratigraphy can increase as much as tenfold even in the near term. For example, the difference in drilling costs for various conditions is as follows:

Location	Cost, $/ft
Lower 48, less than 15,000 feet	18
Lower 48, more than 15,000 feet	80
Lower 48, offshore (less than 600 ft water)	71
Alaska	285

In addition, the gathering systems for these more inaccessible locations will be more expensive. Finally, much new technology needs to be developed in the following areas: geological surveying for more complex stratigraphy, drilling in more than 600 feet of water, and secondary and tertiary recovery. Although estimates of these costs are not available, this information is not needed to validate the real cost increases associated with domestic crude oil processing. Table 8-20 is adequate to justify the projections of increased real costs. The average capital requirement for crude oil additions to reserves during the 6 years between 1967 and 1972 was $2.05 /bbl. Included in this average is the Prudhoe Bay discovery. Excluding the year (1970*) of the Prudhoe Bay discovery, the average cost was $2.39/bbl, which is more representative of the 1960's.

Table 8-20. PRODUCTION AND EXPLORATION INVESTMENT FOR CRUDE ADDED TO RESERVES IN THE U.S. [2, 19]

Year	Additions to Reserves, 10^9 bbl/yr	Capital for Production, Exploration, Geological Surveys, \$$10^9$/yr	Capital Requirement, \$/bbl added to reserves
1967	2.96	4.37	1.26
1968	2.45	5.39	1.91
1969	2.12	5.25	2.13
1970	12.69	4.75	0.33
1971	2.32	3.90	1.37
1972	1.56	6.48	3.68

Using the same assumptions as in all other DCF calculations and a capital investment of $2/bbl for new crude additions to reserves, we determined that the capital required to supply 16.4 million bbl/yr (50,000 bbl/day refinery with 328.5 on-stream days) for 25 years was $810 million. By making a conservative simplifying assumption that the annual operating costs associated with exploration, development, and production were only 10% of the capital requirements, the price of this new crude oil delivered to the refinery would be more than $17.50/bbl to obtain a 12% return on investment. This calculation places crude oil processing on the same basis as coal and oil shale processing; i.e., the cost of obtaining the raw feedstock is evaluated over the life of the project.* The premise is that a new fuel conversion plant will not be constructed unless feedstocks are available over the life of the program. For a new crude refinery, the acquisition of the feedstock must be based upon current and future costs associated with finding new supplies of crude. The current cost (average cost between 1967 and 1972) of finding new crude in the U.S. was $2.00/bbl.

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* The actual discovery was made in 1968. The statistics were not included until 1970.

Some would argue that it is not necessary to have all the required 410 million barrels on hand at the beginning of a project (50,000 bbl/day refinery). After all, the U.S. current reserves-to-production ratio is nearly 50% of the assumed 25-year program life. This new assumption would translate into an approximate price of $8.75 bbl for crude oil instead of the previously quoted $17.50/bbl. However, exploration and production costs could increase up to tenfold. A threefold increase in exploration and production costs in the next 10-15 years would still translate into a crude price of $20.00/bbl, assuming a reserves-to-production ratio of 10. Depending upon the assumptions that are used, the cost of crude oil will fall between about $34/bbl and about $50/bbl by the year 2010.

Underlying this analysis is the assumption that the probability of finding any additional secure supergiant oil fields is very low. (A supergiant field is one with proved reserves in excess of 30 billion barrels.) Currently, there are 10 such fields worldwide: six were discovered prior to 1950, three in the 1950's, and one in the 1960's. The discovery rate of these supergiant fields has slowed despite the development of more effective exploration techniques and increased drilling activity.

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* Based on the above DCF assumptions, a price of $7/bbl could indicate that an $0.80/bbl capital investment is needed to develop the necessary reserves. Although no industry investment data are readily available for the 1940's and early 1950's, this figure appears to be reasonable. Further, the development cost in the Middle East is approximately $0.50/bbl. Note that this figure translates into a price of $4.30/bbl based on the same assumptions. This price approximates the world price of oil in early 1973.

The early recognized existence of these supergiant fields, which were discovered at minimal costs, has given the false impression that other, similar fields can be obtained at "replacement costs." The largest of these fields is equivalent to 60% of all known U.S. reserves plus past production. During the last 20 years, an average of 14 billion bbl/yr was discovered outside these fields in worldwide exploration, but this represents only 7% of worldwide consumption. As in the situation within the U.S., most of the world demand for crude oil is being supplied from additions to reserves made prior to 1960.

Nearly 60% of today's known crude supplies were located prior to 1950. In 1950, the world's consumption of oil was 10 million bbl/day. At that time, existing supplies apparently would last more than 100 years. During the next 23 years, oil products were priced below other energy sources. Consequently, the increase in the consumption rate of petroleum products was 8% per year, whereas the total increase of other energy products, primarily coal, was only 2% per year. In 1973, the consumption rate of crude oil was 57 million bbl/day. During these 23 years, an average of only 3.8 million bbl/day was added to reserves. If a conservative 5% growth rate of oil consumption is assumed through 1990, the consumption rate in 1990 would be 90 million bbl/day. To support this consumption, the finding rate must be increased by a factor of 6 just to keep the supply equal to demand.

The world statistics were cited because some believe that an abundant supply of foreign oil will soon be available in the marketplace and that the "artificial" prices currently being posted will revert to the early 1973 price of $4.50/bbl, or to an even lower level. This analysis clearly indicates otherwise.

8.7.5 Future Shale-Oil-Production Cost Analysis

The calculated base price (1973) of a 50:50 mixture of gasoline and distillate produced from oil shale is $\$2.05/10^6$ Btu. This figure is based upon underground mining of 30 gal/ton oil shale. Much of the oil shale to be used during the mid- and far-term time frames will only contain 15 gal/ton oil. Therefore, some real cost increases will be associated with processing this less desirable oil shale.

First, significant process improvements are not expected to offset these real cost increases because many of these anticipated improvements have already been factored into the analysis. For example, the calculated base price includes the assumption that about 270 tons of oil shale can be mined per man-day, which is almost 20 times the current average coal productivity rate for underground mining and more than 8 times the current average rate for surface mining.

In the base case for oil shale, approximately 58% of the capital and operating costs are associated with ore processing to the point at which the crude shale oil has been removed from the shale. Included in this figure is the cost associated with waste shale disposal. The remaining 42% of the cost is for upgrading and refining the extracted oil. Few technological improvements are anticipated in the latter area because of the similarity with crude oil processing — a mature technology.

For gasoline and distillate hydrocarbons derived from oil shale, nearly 90% of the real cost increase is associated with mineral extraction and shale processing and the other 10% of the real cost increase is associated with obtaining the adequate supplies of water that are required to support this industrial development.

The two principal variables in mineral extraction are the assay, which can vary between 15 to more than 35 gal/ton, and the density of the seams, some of which exceed 40 feet in diameter. The calculated base 1973 cost was based on processing only the highest ore concentration in the most desirable seams. The attendant high mining rates and low capital investment for underground mining are not realistic for extensive industry development. The differences between estimated oil shale and coal mining rates and costs are shown below. (These oil shale mining rates have not been achieved, only estimated.)

	Rate, tons/man-day	Capital Cost, $/tons mined
Deep Mining		
Oil Shale	271	4.50
Coal	13	20
Surface Mining, Coal	35	12

The most current estimate of oil shale reserves is that less than 33% contain 30 gal/ton oil shale. A few deposits with seams greater than 40 feet in diameter have been identified; however, there is no known reliable correlation between assay and seam diameter. We estimated that two adjustments will have to be made in mining rates and costs to take less desirable seams into consideration for large-scale development of the oil shale industry during the near- and mid-term periods. No adjustment was made for shale assay in the near-term period.

The first adjustment to be realized in the 1980's lowers the mining rate from 271 to 135 tons/man-day and increases the capital cost from \$4.50 to \$9/ton of output. This adjustment adds \$0.65/10^6 Btu to the cost of new shale oil purchased.

A similar adjustment would be required 5-10 years later according to the implementation schedule of a Model I scenario (Section 11). At this time, the mining rates drop from 135 to 70 tons/man-day, and the capital costs increase from \$9 to \$14/ton of annual output. This adjustment adds another \$0.62/10^6 Btu to the cost of producing new incremental shale oil.

To place these two adjustments in perspective, note that oil-shale-mining rates are still twice surface coal-mining rates and more than 5 times underground coal-mining rates. Further, it is being accomplished for only 70% of the capital cost associated with deep coal mining.

Another real cost that will be increased is that of obtaining water. The Bureau of Reclamation's estimate of water availability in the area of the Green River Formation is 5.8 million acre-ft/yr (122 million bbl/day). However, only 11% (11 million bbl/day) is uncommitted and could be made directly available for commercialization of this industry. This quantity of water would support the production of about 2 million bbl/day of shale oil, approximately 56% of the anticipated total production (according to the scenario based on Model I energy supply). The economic basis used to determine water costs was 30¢/1000 gal. If adequate water is not available, major capital expenditures will be required to transport the water over longer distances.

Pipeline capital costs vary between 25¢ and 75¢/bbl/day/mile. We have assumed that 60% of the required water must be transported, an average of 150 miles (due to the terrain associated with the Green River Formation), for a capital cost of \$0.75/bbl/day/mile. The capital cost of the transportation portion of the water system is \$25 million. Because of the general lack of water in the area, we have assumed that another \$125 million would be required for the collection and storage portions of the system, both at the source of supply and at the plant site. The annual operating cost of the total water system was estimated at 10% of the capital investment. At the beginning of the mid-term period, these costs will add another \$0.62/10^6 Btu to the cost of new incremental shale oil.

In the mid term, the 15 gal/ton ore will have to be mined, so almost twice as much ore will have to be processed. In addition to doubling the mining production and the cost for new incremental shale oil, the costs of retorting, particulate control, and spent shale disposal will increase, which will add \$1.80/10^6 Btu to the cost of new incremental shale oil.

In the far term, oil shale seams that are comparable to current (1973) coal seams will have to be mined. Oil shale mining productivity will drop from about 70 to about 35 tons/man-day, and the capital cost of oil shale will increase from \$14 to \$20/ton of productivity. Consequently, another \$1.25/10^6 Btu will be added to the cost of producing shale oil. Table 8-21 reflects the consequence of this and all other real cost increases for oil shale production.

8.7.6 Future Coal-Processing Cost Analysis

Three coal-processing schemes are considered in this study: 1) coal to an equal mixture of gasoline and distillate, 2) coal to methane, and 3) coal to SNG. The basic assumption used in calculating the respective base product price in 1973 was that all coal could be supplied at mine mouth for \$0.30/10^6 Btu. This assumption was made to ensure that uniform coal extraction premises and calculations were used in the overall analysis. However, this coal cost is too optimistic when assessing the development of a new coal-based synthetic fuel industry. In the future, the rapid exploitation of coal reserves required by the rapid growth of a coal-fuel industry, per the requisites of this study, makes this coal cost inadequate.

Table 8-21. REAL COST INCREASES OF SHALE OIL PRODUCTION

Period	Description	Operating Cost		Capital Cost		Price	
		Base	Increment	Base	Increment	Base	Increment
		$\$10^6$				$\$/10^6$ Btu	
Near Term	Base: 271 tons/day Capital Cost: $4.5/ton 30 gal/ton shale	51.2	--	473.7	--	2.05	--
	Production: 135 tons/day Capital Cost: $9/ton 30 gal/ton shale	72.1	20.9	597.2	123.5	2.70	0.65
	Production: 70 tons/day Capital Cost: $14/ton 30 gal/ton shale	97	24.9	700	202.8	3.32	0.62
Mid Term	Water Capital Cost: $\$150 \times 10^6$ Operating Cost: $\$15 \times 10^6$	112	15	850	150	3.94	0.62
	Production: 70 tons/day Capital Cost: $14/ton 15 gal/ton shale	167	45	1217	367	5.74	1.80
Far Term	Production: 35 tons/day Capital Cost: $20/ton 15 gal/ton shale	244.6	77.6	1304	87	6.97	1.23

For bituminous coal with a heating value of 24×10^6 Btu/ton (Eastern coal), this $\$0.30/10^6$ Btu cost is equivalent to $7.20/ton. With a heating value of 16×10^6 Btu/ton (Western coal), this quoted cost is equivalent to $4.80/ton. Because almost 85% of current coal production is in the East, these statistics translate into an average coal price of $6.84/ton. This base price is somewhat lower than the average U.S. mine-mouth coal price of $7.66/ton in 1972. However, these prices are well within tolerance when the range of regional coal prices during 1973 is taken into consideration. These prices varied from 1.90/ton to more than $25/ton.

The first objective is to establish the current and future capital and operating costs of delivering new incremental raw coal feedstock to a mine-mouth fuel conversion plant. After these data are quantified, they can be used in the standard DCF calculation. The basic requisites are the capital and operating costs of putting surface and deep mines into production.

Table 8-22 is an estimate (in 1973 dollars) of the itemized investment requirements for a new 1 million ton/yr mine. Table 8-23 is an estimate of the operating costs for an underground mine. The total capital requirement for a surface mine was estimated at $12 million for a 1 million ton/yr mine. Table 8-24 summarizes the components of the annual operating costs of surface mining. By using these estimates of capital and operating costs for mining and calculating the cost of coal based on the standard DCF criteria, the cost of new deep-mined coal is $16.23/ton, and the cost of new surface-mined coal is $8.05/ton. In 1972, 275.7 million tons, or 46% of the total coal production, was from surface mines, and 319.7 million tons, or 54% was from deep mining. The weighted average of the estimated costs for new coal via the standard DCF criteria is then $12.46/ton ($4.88/ton higher than the average 1972 production cost).

The cost of "new" coal is higher than the average 1972 mine-mouth cost ($7.66/ton) because either the coal industry is not averaging a 12% return on its investment and/or the "book value" of its fixed assets is less than the capital requirements depicted in the estimates.

Table 8-22. CAPITAL REQUIREMENTS FOR 1 MILLION TON/YEAR UNDERGROUND MINE

Component	Cost, $1000
Underground Equipment	5,750
Trucks, Bulldozers, etc.	175
Exploration	50
Safety Equipment	150
Mine Drainage Equipment	30
Water and Oil Storage	20
Power Substation and Distribution	75
Portal	70
Ventilation	100
Preparation Plant	4,250
Buildings (Ship, Bathhouse, etc.)	500
Site Preparation	25
Supply Yard	10
Railroad Siding	200
Slope	3,250
Shafts	2,400
Slope Belt and Drive	3,000
Total	20,055

Table 8-23. ANNUAL OPERATING COSTS OF UNDERGROUND MINING

Cost Component	Annual Cost, $1000
Utilities	200
Labor	
Miners (12.5 tons/man-day, $46/day, 227 days/yr)	3,600
Welfare Fund ($0.7/ton)	700
Maintenance Labor (3% of plant investment)	600
Supervision (15% of operating and maintenance labor)	630
Administration and General Overhead (60% of total labor, including supervision)	2,900
Supplies	
Operating (30% of operating labor)	1,080
Maintenance (3% of plant investment)	600
Local Taxes and Insurance (3% of plant investment)	600
Total	10,910

Table 8-24. ANNUAL OPERATING COSTS OF SURFACE MINING

Cost Component	Annual Cost, $1000
Utilities	100
Labor	
Miners (37.1 tons/man-day, $46/day, 225 days/yr)	1,300
Welfare ($0.70/ton)	700
Maintenance (3% plant investment)	360
Supervision (15% of operating and maintenance labor)	250
Adminstration and General Overhead (60% of total labor including supervision)	1,150
Supplies	
Operating (30% of operating labor)	390
Maintenance (3% of plant investment)	360
Local Taxes and Insurance (3% of plant investment)	360
Total	4,870

By using 1972 price and productivity data and the capital and operating costs estimated, a set of simultaneous equations was solved to obtain a reasonable estimate for the current 1973 return on investment and "book value" of fixed assets for the coal industry. This calculation indicates that currently the return on investment is about 6%, and the "book value" of the existing equipment is essentially zero.

The objective of this mining cost analysis is to place all fuel extraction and conversion processes on an equal basis for comparison. This requires an adjustment in coal prices so that required new capital expenditures for coal extraction can be discounted on a consistent basis with crude oil, oil shale, and uranium. Further, new incremental coal obviously cannot be placed on-stream without an adequate return on investment. The increased demand for coal in 1972 and early in 1973 apparently has brought coal supply and demand back into balance. In fact, the numerous announced price increases indicate that coal demand may exceed production capacity this year. In January 1973, the average coal cost to the electric utility industry was 37.8¢/10^6 Btu. In January 1974, this cost had climbed to 51.4¢/10^6 Btu, an increase of nearly 36% in 1 year.

In summary, a near-term real cost increase is associated with the ability to attract the capital for new production capacity. Because 1973 appears to be a transition year, a reference base must be established to assess the necessary future adjustments. The following shows the basis for this adjustment in coal costs.

Mine Type	Eastern Coal, 24×10^6 Btu/ton	Western Coal, 16×10^6 Btu/ton
	$\$/10^6$ Btu	
Deep Mine ($16.23/ton)	0.68	1.01
Surface Mine ($8.05/ton)	0.34	0.50

Currently 85% of coal production is in the East. We have assumed that all Eastern mining is deep-mining and Western mining is surface-mining.* These assumptions allow us to determine an average coal price based on current cost and productivity patterns and a 12% return on investment. This price is $\$0.65/10^6$ Btu, which is the estimated price of new incremental coal in 1972. Therefore, the first real cost increase is $\$0.35/10^6$ Btu for new incremental coal extraction capacity (the difference between the calculated average cost for near-term mine-mouth coal at a 12% return on investment and the $0.30/Btu used to establish the initial, 1973, base costs of coal conversion processes).

The consequences of this real cost increase on the coal conversion process are reflected below:

Cost Components	Coal Conversion Process SNG	 Methanol	 Gasoline Mixture
	$\$/10^6$ Btu		
Base Cost	2.15	3.88	2.80
Incremental Cost	0.59	0.89	0.84
Near Term Cost	2.74	4.77	3.64

In 1970, 176 locations in the U.S. were identified as feasible sites for SNG plants. About 150 million tons of recoverable and uncommitted coal would be necessary to each of these plants. Further, these locations have water resources adequate for supporting SNG plants — but not necessarily other types of plants because some plants (e.g., methanol) require considerably more water per plant. These known reserves are equivalent to 26.4 X 10^9 tons of coal. This number of plants and the associated reserves were based on an assumed SNG selling price in accordance with economics prevailing at the time of this previous study. The production costs for the pattern process used in this study are necessarily higher, and more sites for coal conversion plants are feasible at higher product selling prices.

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* State reclamation costs in the East are nearly $2.00/ton. These costs were not included in our estimates.

An interesting observation is obtained when total coal requirements are determined for the Model I scenario (Section 11) of coal conversion processes over 30 years, which is 5 years beyond the planned program life. This extension is justified because of the many uncertainties in the precise definition of these reserves. Nominal-sized, 250 billion Btu/day plants are assumed here for illustration. These results are shown in Table 8-25.

Table 8-25. TOTAL COAL REQUIREMENT

Fuel Conversion Process	No. of Nominal Plants*	Ton/Plant/Day	Annual Product Reqmt.	30-Year Reqmt.
			10^9 tons	
SNG	100	9.5	0.950	28.5
Methanol	63	13.2	0.832	24.9
Gasoline-Distillate Mixture	108	12.2	1.328	39.8

* Nominal plant is defined as 250 billion Btu/day output; these are not necessarily the same size plants described in Appendix B or in the scenarios of Section 11.

The 176 locations of known coal reserves and with water supplies adequate for SNG plants are limited to 26.4 X 10^9 tons of coal. Nevertheless, this represents only 39% of the total coal requirements for the proposed schedule (28% if methanol is included, but this is not considered possible per the scenarios of Section 11).

According to the planned synthetic fuel industry scenarios, the stated coal reserves, 26.4 billion tons, that are capable of being mined with existing technology, with adequate water supplies, will be allocated to existing plants in the near term. After 1990, during the mid term, it will be necessary to begin exploiting less desirable coal reserves — less desirable from three viewpoints: accessibility, seam thickness, and heating value. We have assumed that the effects of the lower heating value will not change dramatically, that the ratio of strip mining to deep mining will stay the same, but that the capital cost of mines will double and the operating cost will increase 50%. These cost increases are associated with the lack of accessibility to thicker coal seams. The net result of these real mining cost increases is $\$0.37/10^6$ Btu, so the new average price of coal is $\$1.03/10^6$ Btu.

During this mid term, we also have assumed that, for each plant in production, water must be collected and transported 100 miles to the plant. As previously stated, the number of locations that have been identified are capable of supporting both the coal and water requirements for only about 39% of the anticipated total coal conversion plant requirements (Model I scenario). Further, much of the existing coal reserves is located in the Western States, where water is scarce and/or clustered in a specific region; more than 25 potential locations are in Illinois. We estimate the per-plant capital cost of the collection of water and its transportation to and storage at the plant site will be $150 million, and the annual operating cost will be $15 million.

The impacts of these mid-term-period increases on the costs of obtaining coal and water for each of three coal conversion processes are shown in Table 8-26.

Table 8-26. SYNTHETIC FUEL COST INCREASES DUE TO COAL AND WATER DEPLETION IN THE MID-TERM PERIOD

	Coal Conversion Processes		
	SNG	Methanol	Gasoline Mixture
Cost Components	$\$/10^6$ Btu		
Near-Term Cost	2.74	4.77	3.64
Cost Increase	1.26	1.70	1.65
Mid-Term Cost	4.00	6.47	5.29

Toward the end of the mid-term period, the ratio of surface-mining to deep-mining production is assumed to begin to change. In the mid-term, this ratio was held constant at 4:1. By the end of the far term, this ratio will reverse to 1:4, because the surface deposits will have been depleted to the point that most new coal will be mined underground. The ratio of the capital and operating costs of surface mining to those of deep mining is nearly 1:1.67, and the corresponding production ratio is 1:2.8. As these ratios reverse, there will be a corresponding real cost increase. (It should not be inferred that, because these ratios are constant, technological improvements were not considered. Technological improvements were considered in the derivation of the real cost increases in the mid term in the same proportion.)

The impact of these real cost increases on the respective coal processing schemes in the far term is shown in Table 8-27.

Table 8-27. SYNTHETIC FUEL COST INCREASES DUE TO SHIFTS IN MINING TECHNIQUES AND LOWER HEATING VALUE IN THE FAR TERM

	Coal Conversion Processes		
Cost Components	SNG	Methanol	Gasoline Mixture
	$/10^6 Btu		
Mid-Term Cost	4.00	6.47	5.29
Cost Increase	0.60	0.89	0.87
Far-Term Cost	4.60	7.36	6.16

8.7.7 Future Real Cost Increases for Thermochemical Hydrogen

The only real cost increases anticipated are reactor fuel costs: mining and milling, and enrichment. These cost components represent 40% and 45%, respectively, of the total reactor fuel costs. Present mining and milling costs are based on $8/lb of uranium oxide and $10/lb of thorium oxide. The thorium oxide requirements for the nuclear industry are currently about 10% of the uranium oxide requirements.

The $8/lb uranium oxide (yellowcake) price is based on AEC cost analysis procedures and does not include all costs of a private enterprise situation. The basic cost components in the AEC cost analysis are the "out of pocket" costs of mining, handling, royalty, milling, and mill recovery. Private enterprise real cost components not included are property acquisition, exploration, cost of money, and a return on investment. Consequently, the real costs of uranium (and thorium) extraction are understated, at least from a private industry viewpoint. Historically, the cost components not included in the AEC analysis have not produced inaccurate results because reserves and production capabilities were approximately 50% of demand; therefore, "out of pocket" costs are all that are required to conduct the appropriate incremental cost analysis.

In 1979, demand is predicted to exceed supply, and in 1983 the demand is projected to be 3 times the current production capacity. This situation requires a more detailed analysis of the cost components that previously have been excluded. A detailed analysis in this area is beyond the scope of this program. The basic problem is that this segment of the uranium industry is too decentralized and there is no uniform reporting of economic data other than AEC data. At present, almost 200 mines are servicing some 20 mills to produce 13,000 tons/yr of U_3O_8. This quantity of yellowcake requires the extraction of nearly 7 million tons of ore, 60% of which is surface-mined, and 40% of which is produced from deep mines. The mining rates are comparable with those for coal mining, 50 tons/man-day and 10 tons/man-day, respectively.

Current known U.S. reserves total 273,000 tons of uranium as U_3O_8 at $8/lb, only 4 times the 1985 requirements. The depths of these reserves are as follows: 49% less than 400 ft, 44% between 400 and 2250 ft, and 17% more than 2250 ft. Present production is 60% at less than 400 ft and 30% between 400 and 800 ft. Clearly, radical shifts in mining must occur to tap these reserves. Also, these known reserves are not necessarily adequate to support a new mine for over a 20-30 year life span.

The AEC's estimates[28,29] of exploitable uranium reserves are shown in Table 8-28.

Table 8-28. U.S. URANIUM RESERVES

Reasonably Assured, 1000 tons, U_3O_8	$/lb ($U_3O_8$)	Tons of Ore Mined per Ton of U_3O_8
427	10	500
630	15	800
800	30	4,000
4,800	50	13,000

During the period 1966-1972, from \$0.23/lb to \$1.95/lb has been spent for exploration and development per ton of uranium oxide added to reserves, with the highest value occurring in 1972. Drilling costs have been relatively constant during this period (and very cheap when compared to crude oil drilling costs) \$1.20/ft with exploration and development costs of \$1.30/ft and \$0.90 ft, respectively. During this period, the average depth/hole increased from 187 to 439. If these reasonably assured estimates are correct, the reserves-to-production ratio for \$30/lb uranium oxide is approximately 10 for currently scheduled domestic production during the 1980's. The significant point is the near- to mid-term increase in the amount of ore that must be mined to produce 1 ton of uranium oxide; this is an eightfold increase.

An estimated 9-11 years are required to initiate new incremental mining, milling, and conversion processes (for enrichment). In the mid-1980's, the annual demand for yellowcake is estimated to be 70,000 tons/yr. If this quantity is to be obtained for \$30/lb, almost 280 million tons of ore would have to be mined, a 40-fold increase over current production. (If this quantity is obtained at \$50/lb, the uranium-mining operation would have to be twice the size of the existing coal-mining capacity.) Regardless, it is doubtful that domestic reserves will be developed at a higher expense. Worldwide uranium reserves at \$15-30/lb (U_3O_8) are numerous. Therefore, international trade in uranium will probably be expensive. Further, yellowcake at \$30/lb is considerably cheaper than oil at \$24/bbl (domestic, year 2000) on an equivalent Btu basis. For these reasons, the maximum real price increase for yellowcake is assumed not to exceed 375% by about the year 2000, the far-term period.

Economic analysis of the enrichment sector of the uranium industry is more straightforward. All three plant sites are Government-operated, so the appropriate data are available. These plants were installed between 1944 and 1956, and approximately 67% of the existing capacity was added in the mid-1950's.

Estimates for new enrichment costs can be found in AEC reports.[25, 26] The AEC capital cost estimate for new enrichment capacity is \$157/SWU, based on 1971 dollars. Technology improvements anticipated during the 1970's will decrease this cost to \$144/SWU. Several consortia in the private sector who are doing their own evaluations have reported costs as high as $171/SWU. For this analysis we have used $144/SWU for new technology development. Also associated with the new technology development was a 17% reduction in total power requirements. Because nearly 94% of the operating cost is the cost of power, these savings are significant.

To determine the appropriate power cost for a new enrichment plant, the data generated to determine the cost of the nuclear heat requirements for thermochemical processing of hydrogen were used. The processing of these cost data in the standard DCF calculations produced a power cost of 13.44 mills/kWhr.

For 8.75 million SWU/yr plant, which is comparable to one of the new module additions to the existing enrichment complex, the power requirement is estimated at 2050 MW. For 13.44 mills/kWhr, the annual power cost is $323.46 million. The other operating charges are estimated at $15 million, and the capital requirement at $1 billion. The enriching cost resulting from the standard DCF calculations is $66/SWU. (If the capital cost were $171/SWU, the high value reported, the cost of enrichment would be $81/SWU.) The incremental cost associated with the anticipated 17% power reduction is nearly $4/SWU.

In summary, we anticipate that uranium oxide costs will increase from $8/lb to $30/lb and that enrichment costs will increase from $26/SWU to $66/SWU. In turn, these cost increases should increase the cost of the reactor heat output by approximately $\$0.70/10^6$ Btu, which would result in a cost increase of hydrogen of $\$1.40/10^6$ Btu. However, the cost analysis just described does not include a credit for the recycle of U^{233} (bred from Th^{232}). This recycling of U^{233} is estimated to reduce the overall HTGR fuel requirements by 60% over the life of the project. This results in a potential cost increase of $\$0.84/10^6$ Btu for thermochemical hydrogen by the far term.

As previously stated, a 1% increase in heat transfer or energy conversion efficiency is equivalent to a $\$0.12/10^6$ Btu reduction in the cost of producing hydrogen. Such improvements can be achieved in two areas, the reactor and the chemical reaction cycle. The thermochemical process efficiency used in this analysis was 50%. This energy conversion efficiency (reactor plus chemical reaction cycle) can be improved to 55% by the far term.

Such an improvement is equivalent to a reduction of $0.60/$10^6$ Btu in hydrogen production cost.

The net result of the future cost analysis of the production of thermochemical hydrogen is that the base 1973 cost of $4.55/$10^6$ Btu will increase to $4.79/$10^6$ Btu.

8.7.8 Future Cost Analysis Summary

The projected future costs associated with delivering synthesized fuels to the service stations are depicted in Table 8-29. These costs are based upon the cost components described in the preceding sections. There is a reasonable potential for other real cost increases not reflected in these sections. They were not included because, being in the realm of societal impacts and human factors, they cannot be quantified within the scope of this study and/or because these cost increases are generally applicable to all candidate fuel schemes; therefore, they would not contribute directly to comparative analysis.

Because the synthetic fuel processing industry will be labor-intensive and frequently located in sparsely populated areas, additional time may be required to attract and train the appropriate labor force. This problem is compounded by competition among candidate-fuel sectors for skilled personnel. A common skilled labor classification for the coal, the oil shale, and the uranium industries is miners. Assuming reasonable productivity increases per miner, a fivefold increase over the present mining manpower, to 750,000 miners, will be needed by the early 1990's. No attempt has been made to quantify the number of professionals required in this area; however, this may represent a greater constraint, because less than 300 new graduates are entering this profession in the U.S. each year.

The construction period, 3.5 years, used in this analysis was for ideal conditions. Considering possible industrial implementation schedules, there is a high probability that the construction period could be extended to 9 years, the current planned schedule for nuclear reactors. Such a slippage would add between $0.50 and $1.00/$10^6$ Btu to the unit cost of the fuels involved.

Another consideration is the cost of money, i.e., the expense associated with attracting new capital. Current interest rates are at least 33% higher

Table 8-29. PROJECTED COSTS OF CANDIDATE ALTERNATIVE FUELS[a]

Resource Base and Synthetic Fuel	Production Costs 1985	Production Costs 2000	Production Costs 2020	Transmission and Distribution Costs	Total Costs 1985	Total Costs 2000	Total Costs 2020
	$/10^6 Btu						
Coal							
Gasoline and Distillate Oil[b]	3.64	5.29	6.16	1.06	4.70	6.35	7.22
Methanol	4.77	6.47	7.36	1.34	6.11	7.81	8.70
SNG[c]	2.74	4.00	4.60	2.04	4.78	6.04	6.64
Oil Shale							
Gasoline and Distillate Oil[b]	3.32	5.74	6.97	1.06	4.38	6.80	8.03
Nuclear Heat							
Hydrogen[d]	f	4.79	4.79	3.83	f	8.62	8.62
Hydrogen[e]	f	4.79	4.79	2.21	f	7.00	7.00
Domestic Crude							
Reference Gasoline	2.76	4.56	7.82	1.20	3.96	5.76	9.02

[a] Basis: low heating values of the fuels.

[b] 50:50 product mix, average price.

[c] SNG transmission and distribution as a gas, liquiefied at service stations.

[d] Thermochemical hydrogen transmission to terminals as a gas, liquefied and distributed in liquid hydrogen trucks to service stations.

[e] Thermochemical hydrogen transmission and distribution as a gas,combined as a metal hydride at service stations.

[f] Technology gap, near-term hypothetical production cost, $4.55/10^6 Btu.

than those in 1973. Based upon the industry scenarios of Section 11 (or anything like these schedules), the demand for capital goods will continue to be strong; therefore, interest rates will not decrease appreciably. The initial yearly capital requirements for the oil shale industry, for example, will be approximately $1 billion, or nearly 20% of the planned capital expenditures for the petroleum industry between 1971 and 1974 inclusive. In general, to meet the capitalization schedule, the industry debt-to-equity ratio must be increased. A precise estimate of these consequences is difficult to obtain. A first-order approximation can be obtained by increasing the "cost of capital" in a DCF calculation, holding all other parameters constant. The resulting difference in the cost of the fuel product over the project life, 25 years, is from $\$0.40/10^6$ Btu to $\$0.60/10^6$ Btu (added to the cost of producing the product).

The ratios pertaining to water requirements are shown in Table 8-18 to emphasize the criticality of water in many potential site locations. Although allowances were made for the potential cost increase of transporting incremental water requirements to these sites, some of the regional consequences have to be considered when more and more synthetic fuel plants are placed on-stream. Seasonal weather variations could affect production at plants with limited water availability. When water costs are approached from this point of view, the estimates used may prove to be too conservative.

An additional socio-economic consideration is the cost of the development of new communities in sparsely populated areas to attract personnel. This incremental cost increase is only about $\$0.10/10^6$ Btu over the project life.

That all these incremental costs will occur simultaneously across the industry is highly unlikely. Nevertheless, some portion of these costs probably will be incurred in the aggregate. Because of the strong demand for energy, some of these additional cost increases will be experienced to various degrees in all three time frames.

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9. TECHNOLOGY AND INFORMATION GAPS

In this study, a "technology gap" is defined as a lack of technical capability that makes an otherwise acceptable fuel impractical. This technical problem might be solved by intensive research and development. We have further qualified technology gaps as serious or moderate. A serious technology gap eliminates a fuel from general supplementive use (as an alternative fuel) before the year 2000 because of the lead times required for research, development, prototype achievement, demonstration, operation and testing (plant or product), and production plant (or industry) construction and operation. Less serious (moderate) technology gaps, such as a fuel storage technique or an emission control device, eliminate a fuel for the near term (before 1985).

As the study progressed, we encountered another type of gap: information. In some cases, the data necessary to properly evaluate the potentials of candidate fuels do not exist, are imprecise and subject to controversy, or are subject to restricted access. In other cases, laboratory or vehicle tests are required to obtain measurements.

9.1 Serious Technology Gaps

9.1.1 Solar Energy to Chemical Fuel

With present agricultural technology, solar energy is converted to plant material at an efficiency of about 1%. After the latter's conversion to a chemical fuel, the overall efficiency is about 0.5%. Although the energy is free, the land area and capital investment are not. To be practical, a solar plantation needs higher efficiencies (2-5% for the crop). The lack of an efficient and economical fuel crop constitutes a serious technology gap.

A heat-to-work (or fuel) cycle based on solar energy (alone) that could achieve an overall efficiency of 15-25% would be a significant development. Concepts have been proposed, but specific processes that could, by demonstration, lead to proof of concept do not exist. Such a process would decrease the land area requirements of current agricultural methods by a factor of 30-50.

9.1.2 Demonstration of Nuclear Fusion

As a potential source of energy, almost without raw material limits, fusion reactors promise to be an eventual solution to the continuing energy crisis. Aside from capital investment limitations, reactors creating the fusion of deuterium nuclei and extracting some of the produced energy could be used for electricity generation or process heat applications. However, demonstration of net energy production from a continuously operating fusion mechanism is not anticipated in the near future; this requirement constitutes a serious technology gap.

9.1.3 Hydrogen From Water

A nonfossil and nonelectric process for producing a chemical fuel from a renewable material resource is highly desirable. To date, the best prospects are for the thermochemical production of hydrogen from water. Such a process might be coupled to solar energy, nuclear fusion process heat, or nuclear fission process heat to provide adequate amounts of a chemical fuel in the future. Methane or alcohol from water and a renewable carbon resource (e.g., carbon dioxide, plants) or an extensive resource (limestone) are other possibilities.

Of key importance is the ability to extract useful energy from nuclear heat in the future at higher efficiencies than are now possible. Although involved, an exercise with energy demand and supply Model I (optimistic for self-sufficiency) illustrates this point. If the heat from future nuclear and coal sources is utilized at an overall efficiency of 30%, some deficits occur in certain market sectors in all time periods. With this condition we can never be self-sufficient, even though we have plenty of raw heat as "prime" energy. In practice, nuclear reactors are now about 30% efficient. Model I assumes a 35% conversion efficiency; this results in potential self-sufficiency from about 1985 until 2000. If we achieve an overall conversion efficiency of 40%, we can be self-sufficient with nuclear fission (breeders required) and coal for a much longer period.

9.2 Moderate Technology Gaps

9.2.1 Breeder Reactors

The production of fissile fuels (uranium or plutonium) from fertile materials (thorium or depleted uranium) is a practical requirement for nuclear energy to be assured as a major energy supply beyond 1985. The breeding of U^{233} or Pu^{239} has been demonstrated, and the limited production of U^{233} from Th^{232} occurs in the newly commercialized HTGR's. However, demonstration of a fast breeder reactor is needed to show commercial potential for net production of fissile fuel. On the basis of the data in Table 3-2, the development of plutonium breeding could result in 75 times as much heat energy from nuclear reactors.

9.2.2 Distribution of Cryogenic Fuels

Two of the candidate alternative fuels, hydrogen and SNG, can be distributed as cryogenic liquids. The technology and the hardware for transferring such fuels from different containers exist, but safety requirements are necessarily extreme, and the equipment is expensive and sophisticated compared with that for conventional fuel transfer. For practical distribution to vehicles at service stations, the following techniques and equipment are required:

- Safe filling of an initially warm tank by reliquefying, venting (if safe, economical, and environmentally acceptable), or combusting the vaporized portion of the fuel
- Fail-safe devices for containing the cryogenic liquid and preventing human contact
- Prevention of liquid air or liquid oxygen formation in the case of liquid hydrogen fuel.

In the case of liquid hydrogen, a large portion (about 30%) of the fuel's heating value is spent in liquefaction. More efficient processes or a cycle in which the latent heat is used would lower the distribution costs for hydrogen and make them more attractive.

9.2.3 Vehicle Storage of Hydrogen

At present, no satisfactory method for tanking sufficient hydrogen on-board a vehicle exists. Three options have been considered: liquid hydrogen and metal hydrides, which have drawbacks, and chemical storage, which shows promise.

1. Liquid hydrogen is bulky, requires vacuum-jacketed tanks, and suffers from the problems enumerated above.

2. Metal hydride storage is too heavy and, in most cases, requires moderate- or high-temperature heat for decomposition to "generate" the hydrogen. The logistics of hydride regeneration have not been defined sufficiently, and the most practical and cost-effective scheme has not been delineated. A systems study is required. The options are a) to recharge the hydride in a container fixed on-board the vehicle, b) to replace the vehicle container (canister) with another that is charged at the service station or elsewhere, or c) to dump the spent hydride at the service station and refill the container, which remains on-board the vehicle, with regenerated hydride.

3. Hydrogen can be carried by chemical bonding as another material, preferably as a liquid, such as methanol, gasoline, formaldehyde, or acetic acid. These chemicals can be decomposed (reformed) on-board the vehicle to produce hydrogen. Feasibility studies and experimental programs are required.

9.2.4 SLPG From Coal

Coal is easily gasified to carbon monoxide and hydrogen. Selective formation of C_2, C_3, and C_4 hydrocarbons from this synthesis gas requires a catalytic process not yet known, or at least not published. If a suitable catalyst were developed, this process would make SLPG a more viable alternative fuel.

9.2.5 Vehicle Combustion of Solvent-Refined Coal

According to Model I (and inherent in Model II), direct combustion of coal as a fuel would help solve our future energy supply problems because resource-to-fuel conversion efficiencies would probably exceed 90% (coal to solvent-refined coal). An external, continuous-combustion engine cycle could utilize solvent-refined coal, but problems with ash and gaseous pollutants (primarily sulfur dioxide in addition to carbon monoxide, NO_x, and possibly traces of heavy metals, would have to be solved. In addition, a suitable vehicle-refueling scheme would have to be devised. With convenient distribution and acceptable combustion, solvent-refined coal would become a more desirable alternative fuel.

9.3 Information Gaps

The following questions could be answered by performing laboratory experiments:

a. What additives for methanol and gasoline blends allow up to 1% (or more) water to be accommodated without phase separation?

b. What additives for methanol and gasoline blends prevent phase separation at low temperatures (0° to −20°F)?

c. What additives for methanol decrease the flash point of the mixture from 50°F (methanol) to −20°F (mixture)? These additives would enable quick and convenient cold-engine starts. However, the additive should not adversely increase high-temperature vapor pressure and result in vapor lock at normal engine-running temperatures.

The following questions could be answered by vehicle and/or engine tests conducted by scientific methods with appropriate controls:

a. How energy-efficient are vehicles with spark-ignited, internal-combustion engines that meet 1977 emission standards when these vehicles are operated on —

- Conventional gasoline (reference)?
- Coal-derived gasoline?
- Shale-oil-derived gasoline?
- Blends of coal gasoline and/or shale oil gasoline with conventional gasoline?
- Methanol?
- Methanol-gasoline blends?
- Hydrogen?
- SNG?

To obtain meaningful answers, knowledge of and control over fuel combustion ratings, air/fuel equivalence ratios, and vehicle characteristics are required. These efficiencies can affect consumer costs, but they probably cannot have sufficient impact on overall energy requirements or resource depletion.

b. How energy-efficient are experimental engines of different types (Rankine, Brayton, etc.) when they are operated on different alternative fuels?

c. What are the emissions and pollutants from the alternative fuels when used in a standard engine? Do the additives for the methanol-gasoline blends cause new pollutants? When hydrogen is used as a fuel in an internal combustion engine, is hydrogen peroxide emission significant? If so, can it be controlled or reduced to acceptable levels if necessary?

The following hardware development may be necessary, depending on alternative fuel implementation:

a. A safeguard device for (catalytic) combustion on the vehicle tank to prevent venting of hydrogen, SNG, or LPG vapors from becoming a flammability hazard.

b. A service station metering device for methanol that is sensitive to water content; this will deter illegal "watering" of the fuel.

c. A warning device to alert passengers of the presence of methanol vapors inside an automobile. For methanol, the least detectable odor occurs at 100 ppm in air, and the maximum allowable concentration for prolonged exposure is only 200 ppm.

The following information could be derived by further feasibility and impact studies on alternative fuels for automotive transportation:

a. The economic and social impacts of an alternative fuel system based on coal in Montana, Wyoming, North Dakota, and the Four Corners area (New Mexico) as well as in the Eastern States.

b. The economic and social impacts of an alternative fuel system based on oil shale in Colorado, Utah, and Wyoming.

c. The derivation of a continually updated energy demand and supply model in a computerized format, which would permit energy deficits and excesses in future time frames. Emphasis could be given to the automotive sector of the economy. Given a computerized version of the methodology of Section 2, the need for and the quantities and types of alternative fuel could be predicted.

The following information exists but was not available to this study:

a. Actual energy expenditures in the mining, refining, and enriching of uranium for nuclear fuel usage; this information is classified.

b. The numbers and locations of coal-to-synthetic fuel plants versus the selling price of the produced fuel; this information (for SNG) is proprietary.

c. The numbers and locations of oil-shale-processing plants versus the selling price of the produced fuel; this information is proprietary, as are details of experimental in situ shale oil processes.

10. SELECTION OF CANDIDATE ALTERNATIVE FUELS

10.1 Preliminary Fuel Selection

According to the methodology described in Section 2, we have applied information described in Sections 3 through 9 to the potential alternative fuels. The fuel system rating is based on six general categories:

- Adequacy of energy and material availability and competing demands for fuel
- The existence of known or developing fuel synthesis technologies
- Safety (toxicity) and handling properties of fuels
- Relative compatibility with fuel transport facilities and utilization equipment (tanks and engines)
- Severity of environmental impacts and resource depletion
- Fuel system economics (resource extraction, fuel synthesis and delivery, automotive utilization).

In each category, the fuels are rated on a numerical basis of 1 to 5, except for fuel costs, safety, and handling properties, which are normalized to those of reference gasoline. Section 2 explains the normalization procedure. In summary, the indices are as follows:

- Toxicity ratio (fuel concentration in air for 8-hour exposure limit)

$$\left(\frac{\text{ppm fuel}}{\text{ppm gasoline}}\right)^{-1}$$

- Tankage index (weight and volume of fuel)

$$\frac{\text{fuel tankage weight}}{\text{gasoline tankage weight}} + \frac{\text{fuel tankage volume}}{\text{gasoline tankage volume}}$$

- Cost index (fuel at service station)

$$\frac{\text{fuel cost, } \$/10^6 \text{ Btu}}{\text{gasoline cost, } \$/10^6 \text{ Btu}}$$

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The numerical ratings are outlined below.

- Fuel Availability (Energy Sources and Fuels) –

  1 Probable. The energy supply is currently available (potentially) because it exceeds, by a factor of 5 or more, the 25 year-15% transportation demand requirement of about 108 X 10^{15} Btu (as fuel). The fuel is not required elsewhere (in market sectors of higher priority) and would be substantially available for transportation.

  2 Possible. The energy supply is available (potentially) because it is 2-5 times the 25 year-15% transportation demand requirement of about 108 X 10^{15} Btu (as fuel). Although not required elsewhere, the fuel is desired as a chemical commodity.

  3 Speculative. The energy supply is 1-2 times the demand requirement of 108 X 10^{15} Btu (as fuel). The fuel is desired elsewhere.

  5 Not Adequate or Available. The energy supply is less than the demand requirement of 108 X 10^{15} Btu (as fuel). The fuel is required for a high-priority deficit in a market sector other than transportation.

- Synthesis Technology –

  1 Probable. Commercial processes or demonstration plants could be built.

  2 Possible. Synthesis processes are developmental and require pilot-plant testing.

  3 Speculative. Conceptual or laboratory methods exist, constituting a moderate technology gap.

  5 Serious Technology Gap. The synthesis route needs proof of concept and laboratory development.

- Transmission and Distribution Compatibility –

  1 Probably Compatible. The fuel can use the present system.

  2 Possibly Compatible. The fuel has its own system or can use the present system with modifications; some new equipment is needed.

  3 Speculative. Essentially all new equipment is needed for a workable system.

  5 Incompatible. Not only is the fuel incompatible with transport systems, but also new, sophisticated equipment that is needed is beyond practicality.

- **Engine Compatibility** –

  1 Probably Compatible. No changes or very minor changes to the engine are required (e.g., carburetor adjustment).

  2 Possibly Compatible. Some design changes or add-ons and major adjustments are required (e.g., change intake manifold and carburetor).

  3 Speculative. Major engine design changes are necessary, or an existing engine would require extensive rebuilding (e.g., change compression ratio).

  5 Incompatible. The fuel is not suitable for use in the engine type; tests have shown it to be impractical or impossible.

- **Environmental Effects** –

  Of the alternative fuels considered, only solvent-refined coal would be expected to produce emissions of the type that are beyond the capability of automotive emission controls now being developed. Overall system effects cannot be determined at this time. All fuels are given a "2," except coal, which is given a "5."

Table 10-1 shows the application of these criteria to the potential fuels. The numbers in Table 10-1 were assigned for the following reasons:

10.1.1 Synthesis Technology (Section 5)

The survey of synthesis technologies has concluded that acetylene, ammonia, carbon monoxide, gasoline, distillate hydrocarbons, alcohols, and vegetable oils have synthesis processes sufficiently well-developed to be classified as probable (or No. 1).

Solvent-refining of coal is by itself in the "probable" classification, but better methods of sulfur and ash removal would be needed before solvent-refined coal could be used as an automotive fuel.

Hydrazine and methylamine are rated as "possible" because processes that might work directly from synthesis gas and nitrogen have not been developed. With present technology, we must consume "better" fuels such as ammonia and methanol to make these fuels.

SLPG suffers from a moderate synthesis technology gap, described in Section 9. SLPG therefore is rated as "speculative."

Table 10-1. PRELIMINARY FUEL SELECTION BY RANKING RELATIVE TO GASOLINE

Fuel	Synthesis Technology	Fuel Availability Competition			Safety and Handling		Compatibility				Environmental Effects	Costs at Station	Score (Σ)	Final Ranking
		1975-85	1985-2000	2000-2000+	Toxicity	Tankage	Trans-mission	Distri-bution	Conventional Engine	Unconventional Engine				
Acetylene	1	3	2	2	0	10.5	5	3	5	3	2	5.4	41.9	10
Ammonia	1	3	3	2	5	4.7	2	3	3	2	2	2.2	32.9	8
Carbon Monoxide	1	2	2	2	5	41.0	2	5	3	3	2	1.6	69.6	11
Coal (Solvent Refined)	2	3	2	2	0	2.2	2	5	5	3	5	0.8	32.0	7
Distillate Oils	1	2	2	2	1	2.0	2	2	5	2	2	1.0	24.0	2
Ethanol (Agriculture)	1	5	5	3	0.5	3.0	2	2	2	2	2	4.3	31.8	6
Gasoline (Reference)	1	1	2	3	1	2.0	1	1	1	2	2	1.0	18.0	--
Gasoline (Synthetic)	1	2	2	2	1	2.0	1	1	1	2	2	1.3	18.3	1
Hydrazine	2	3	2	2	500	7.6	5	5	5	2	2	9.8	545.4	13
Hydrogen	1	2	2	2	0	6.2	2	3	2	2	2	2.4	26.6	4
SLPG	3	5	5	5	0	2.4	2	3	2	2	2	1.5	32.9	8
Methanol	1	2	2	2	2.5	3.9	2	2	2	2	2	1.2	24.6	3
Methylamine	2	3	2	2	50	3.4	3	5	5	3	2	3.2	83.6	12
SNG	1	5	5	5	0	3.2	2	3	2	2	2	1.5	31.7	5
Vegetable Oil	1	5	5	3	0	2.1	2	2	2	2	2	10.8	39.9	9

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10.1.2 Fuel Availability (Sections 2.3 and 4)

The ratings for fuel availability have been awarded uniformly, except for certain fuels that are sure to be in short supply to the automotive sector because of competition from other demand sectors or technical limitations.

Reference gasoline, refined from domestic petroleum, is graded "very available" in the first time frame. In the second time frame, it is rated "possibly available," acknowledging the relative inelasticity of domestic petroleum supplies. In the post-2000 period, conventional gasoline is expected to be a minority fuel for automotive transportation. In this time frame, it is rated "speculative."

For fuels with a synthesis technology limitation, rated "2," availability is "speculative," at least in the first time frame. The moderate technology gap for production of synthetic LPG from coal effectively eliminates LPG until the mid-term period when the low-level output from newly developed processes would be demanded by other priority markets (residential and commercial).

The agricultural fuels, ethanol and vegetable oils, are given low ratings for availability for the first time frame because of the large amounts of land required by today's agricultural technology for the production of significant amounts of fuel.

SNG and SLPG will be available in very limited quantities during the time frames of this study, and they are considered to be not available for general automotive use.

Other fuels are given moderate availability ratings for all time frames.

10.1.3 Safety and Handling (Appendix A and Section 6)

Data for ratings on toxicity and tankage are taken from the tables of Appendix A. These criteria are quantified by the toxicity ratio and tankage index. The toxicity ratios of hydrazine and methylamine are so high that they effectively eliminate these fuels from further consideration. This seems proper and reasonable for fuels that are more toxic than gasoline by 2 or 3 orders of magnitude.

10.1.4 Compatibility and Utilization (Section 6)

For the preliminary fuel selection, compatibility has been judged in four areas:

- Compatibility with the present transmission system
- Compatibility with the present distribution system
- Compatibility with present automobile engines
- Compatibility with unconventional power plants that might be introduced in the future (stratified-charge, Brayton, Rankine, or Stirling engines or fuel cells).

The ratings recorded for compatibility with transmission and distribution systems have been determined subjectively for the reasons given in Section 6.

The need for fuel compatibility with present or future power plants is clear. Even if only slight modifications to vehicles are necessary, there will be resistance to introduction of the new fuel. Two of the prime movers currently under consideration are most sensitive to fuel characteristics: fuel cells and conventional Otto-cycle engines. Diesel engines are less sensitive, and stratified-charge engines can be designed for operation with several different fuels. Continuous-combustion engines can be designed to accommodate almost any of the potential alternative fuels.

Results of the study on engine-fuel compatibility (Section 6) are summarized and presented in Table 10-2. The ratings in the fuel selection sheet (Table 10-1) were awarded from this table.

10.1.5 Fuel Cost at Service Station (Section 8)

The cost of alternative fuels, as determined by the first-tier (preliminary) method, have been used as a basis for quantifying these criteria. Predicted fuel costs were normalized relative to conventional gasoline at the gas pump in 1973 ($\$2.40/10^6$ Btu).

The cost of fuel at the station does not represent the complete cost story. Some of the fuels listed are substantially more or less efficient than the reference fuel. Outstanding examples are hydrogen (0-50% more efficient), methanol (0-25% more efficient), or hydrazine, which could be used in very efficient fuel cells. The effects of changes in vehicle efficiency on the fuel system cost cannot be determined with sufficient accuracy and documentation.

Hence, the cost of utilization of alternative fuels in vehicles is not included in the fuel system cost.

Table 10-2. ENGINE-FUEL COMPATIBILITY

	Type of Engine				
Fuel	Conventional With Carburetor	Open Chamber Stratified-Charge	Diesel	Brayton	Stirling or Rankine
Acetylene	5	2	5	2	2
Ammonia	3	3	5	2	2
Carbon Monoxide	3	3	5	2	2
Coal	5	5	5	3	2
Distillate Oils	5	2	1	2	2
Ethanol	2	2	5	2	2
Gasoline	1	2	5	2	2
Hydrazine*					
Hydrogen	2	2	2	2	2
LPG	2	2	3	2	2
Methanol	2	2	5	2	2
Methyl Amine	5	3	3	2	2
Natural Gas (SNG)	2	2	3	2	2
Vegetable Oils	5	4	3	2	2

* Fuel-cell fuel.

10.1.6 Selected Fuels

By adding the scores for each fuel in Table 10-1, a ranking of the fuels can be determined. A low score indicates a "good" fuel. The lowest five scores are candidate fuels and therefore are considered in the second tier of examination. The selected fuels are —

- Gasoline
- Distillate oils
- Methanol
- Hydrogen
- SNG.

10.2 Selection of Energy Sources

One requirement in the selection of an alternative fuel system is the determination of whether its domestic resources are adequate to support 15% (or more) of the transportation demand for at least 25 years. Transportation demand is of course greater than automotive demand; hence, this criterion should be adequate with competition (from aircraft) for a commonly desired transportation fuel (distillate oils). If the adequacy of the alternative resource falls below 15%, more than two simultaneous alternative systems are necessary, because the transportation energy shortfall ranges from about 28 to 39% of the total demand until the year 2000, after which it increases. Development of more than two simultaneous alternative systems is not practical, and a system life of less than the nominal life of a fuel-synthesis plant network plus the life of the transmission and distribution system is not realistic. From Section 2 or 4, 15% of the transportation energy demand for the 25 years following 1975 amounts to approximately 108×10^{15} Btu (Model I).

For this study we have chosen to sum 100% of the assured resource base, 75% of the reasonably assured resource base, and 25% of the speculative resource base for finite domestic fossil and nuclear resources. This is an arbitrary but uniform method of estimating the adequacy of a resource base for fuel synthesis. These resources and sums are presented in Table 10-3, in which the adequacy of the resource is rated according to the require- (Section 10.1).

In the case of solar heat, we have taken one average size state, or 2% of the U.S. land area, as an approximation of that potentially available for agricultural production of a crop that could be converted to a fuel for automotive transportation. This is about 45 million acres, and between 1960 and 1973, an average of about 43 million acres of cropland has been withheld from production. In the cases of municipal and feedlot wastes, we have taken the annual supply projected for 1985.

10.3 Fuel Candidates for the Three Time Frames

The approach to detailed fuel selections for each time frame is basically the same as that in Section 10.1. The differences are the quality of information used and the fact that the selection procedure is applied for each of the three time periods with appropriate availability, engine compatibility, and costs.

Table 10-3. ADEQUACY OF DOMESTIC RESOURCES

Finite Resource	Potential Supply, 10^{15} Btu	Adequacy*
Coal	67,100	Probable
Oil Shale	3,230	Probable
Uranium (Fission)		
Burner Reactors	550	Possible
Breeder Reactors	41,250	Moderate technology gap
Tar Sands	127	Not adequate
Deuterium (Fusion)	Unassessed	Serious technology gap

Renewable Resource	Potential Annual Supply	25-Year Fuel Supply	Adequacy*
	10^{15} Btu	10^{15} Btu	
Hydropower			
Total	1.8	37.5	Not adequate
Uncommitted	1.5 (as fuel)		Not adequate
Geothermal Heat	7.7 (as heat)		
Fuel Conversion	2.7 (as fuel)	67.5	Not adequate
Solar Heat (Total Area)	49,000 (as heat)		
2.0% U.S. Area	980 (as heat)		
Agricultural Production	9.8 (as crop)		
Fuel Conversion	4.9 (as fuel)	122.5	Speculative
Tidal Power	Negl	Negl	Not adequate
Wind Power	4.0 (as fuel)	100	Not adequate
Municipal Wastes	2.9 (as heat)		
	1.2 (as fuel)	30	Not adequate
Animal Feedlot Wastes	6.8 (as heat)		
	3.4 (as fuel)	85	Not adequate

* Not adequate = $>108 \times 10^{15}$ Btu.

10.3.1 Near-Term Time Frame (1975-1985)

In the near-term time frame, all criteria remain the same in the first-tier selection, except for the fuel costs and engine compatibility. The reference gasoline cost is \$3.96/10^6 Btu, and the fuel costs are taken from Table 8-29. For the near term, only conventional Otto-cycle engines are considered. Vehicle compatibility is divided between compatibility with "old" (pre-1975) engines — the extent to which these engines would be modified for the new fuel — and compatibility with "new" engines — the extent to which design changes would be needed.

The ranking of the seven alternative fuels selected for detailed study for the near-term time frame, according to Table 10-4, is as follows:

Fuel	Source
Gasoline	Oil shale
Gasoline	Coal
Distillates	Oil shale
Distillates	Coal
Methanol	Coal
SNG	Coal
Hydrogen	Coal

10.3.2 Mid-Term Time Frame (1985-2000)

In the mid-term time frame, "new" vehicles and power plants are considered, and the synthesis processes with moderate technology gaps are considered available. A nuclear hydrogen industry (thermochemical) could be in the early stages of growth by the end of this time frame. Mid-term fuel costs are taken from Table 8-29. The ranking of the seven alternative fuels selected for detailed study for the mid-term time frame, according to Table 10-5, is as follows:

Fuel	Source
Gasoline	Coal
Gasoline	Oil shale
Distillates	Coal
Distillates	Oil shale
Methanol	Coal
SNG	Coal
Hydrogen	Nuclear

Table 10-4. FINAL FUEL SELECTION FOR THE NEAR-TERM TIME FRAME

Fuel	Synthesis Technology	Fuel Availability	Safety and Handling		Compatibility				Environmental Effects	Costs at Station	Score (Σ)	Final Ranking
			Toxicity	Tankage	Transmission	Distribution	Old Vehicles	New Vehicles				
Gasoline (Coal)	2	2	1	2.0	1	1	1	1	2	1.19	14.19	2
Gasoline (Shale)	1	2	2	2.0	1	1	1	1	2	1.11	13.11	1
Methanol (Coal)	1	2	2.5	3.9	2	2	2	2	2	1.54	20.94	5
Hydrogen (Coal)	2	2	0	6.2	2	3	4	2	2	1.40	24.60	7
SNG (Coal)	1	5	0	3.2	2	3	3	2	2	1.21	22.41	6
Distillate Oils (Coal)	2	2	1	2.0	2	2	4	2	2	1.19	20.19	4
Distillate Oils (Shale)	1	2	1	2.0	2	2	4	2	2	1.11	19.11	3
Reference Gasoline	1	1	1	2.0	1	1	1	1	2	1.00	12.00	--

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Table 10-5. FINAL FUEL SELECTION FOR THE MID-TERM TIME FRAME

Fuel	Synthesis Technology	Fuel Availability	Safety and Handling		Compatibility			Environmental Effects	Costs at Station	Score (Σ)	Final Ranking
			Toxicity	Tankage	Transmission	Distribution	New Vehicles				
Gasoline (Coal)	1	2	1	2.0	1	1	1	2	1.10	12.10	1
Gasoline (Shale)	1	2	1	2.0	1	1	1	2	1.18	12.18	2
Methanol (Coal)	1	2	2.5	3.9	2	1	1	2	1.36	16.76	5
Hydrogen (Nuclear)	2	2	0	6.2	2	3	2	2	1.22	20.42	7
SNG (Coal)	1	5	0	3.2	2	3	1	2	1.05	18.25	6
Distillate Oils (Coal)	1	2	1	2.0	2	1	1	2	1.10	13.10	3
Distillate Oils (Shale)	1	2	1	2.0	2	1	1	2	1.18	13.18	4
Reference Gasoline	1	2	1	2.0	1	1	1	2	1.0	12.0	--

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10.3.3 Far-Term Time Frame (2000-2020)

In the post-2000 period, there are no distinctions for engine compatibility or synthesis technology. Methanol is "possible" in availability because it competes with gasoline and distillate oils (preferred fuels) for the same coal and water resources, but, because of process characteristics, less methanol can be made from these resources. The cost increases for fuel production have resulted in minor fuel price differences relative to reference gasoline, which is now the most expensive fuel. The ranking of the five alternative fuels selected for detailed study for the far-term time frame, according to Table 10-6, is as follows:

Fuel	Source
Gasoline	Coal or oil shale
Distillates	Coal or oil shale
Hydrogen	Nuclear
Methanol	Coal
SNG	Coal

Table 10-6. FINAL FUEL SELECTION FOR THE FAR-TERM TIME FRAME (2000-2020)

Fuel	Synthesis Technology	Fuel Availability	Safety and Handling		Compatibility			Environmental Effects	Costs at Station	Score (Σ)	Final Ranking
			Toxicity	Tankage	Transmission	Distribution	New Vehicles				
Gasoline (Coal)	1	1	1	2.0	1	1	1	2	0.80	10.80	1
Gasoline (Shale)	1	1	1	2.0	1	1	1	2	0.89	10.89	2
Methanol (Coal)	1	2	2.5	3.9	2	1	1	2	0.96	16.36	6
Hydrogen (Nuclear)	1	1	0	6.2	2	2	1	2	0.78	15.98	5
SNG (Coal)	1	5	0	3.2	2	2	1	2	0.74	16.94	7
Distillate Oils (Coal)	1	1	1	2.0	2	1	1	2	0.80	11.80	3
Distillate Oils (Shale)	1	1	1	2.0	2	1	1	2	0.89	11.89	4
Reference Gasoline	1	3	1	2.0	1	1	1	2	1.00	13.00	--

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11. CONCLUSIONS AND SCENARIOS

11.1 Near-Term Time Frame (1975-1985)

During the next decade, we will witness the commercial development of a "synthetic" or substitute fuel technology; i.e., fossil resources, other than conventional crude oil and natural gas, will be used for conversion to clean and convenient fuels. In addition, the nuclear industry's energy output should grow by a factor of 6-7 during the decade, but this contribution may be limited to the electricity supply. Unfortunately, the long lead times required by pilot-plant development, testing of demonstration plants, and full-scale plant construction and start-up will prevent these new fuel synthesis technologies from contributing appreciably to the domestic energy supply. In addition, capital investment limitations will be complicated by unusual risk factors stemming from raw material availability and fluctuating foreign supplies of fuels.

The automotive sector will be low in priority during fuel shortages and allocations, and supplies and costs of these fuels will be subject to strong influences from "marginal" supplies that could potentially fill the deficit. These marginal supplies consist of the crude oil produced elsewhere than in North America, and,later in this time frame, synthesized fuels also will be in this category. The immediate economic attractiveness of fuel synthesized from coal and oil shale will depend to a great extent on the price of imported crude oil and finished products. From the standpoints of longer term economics (international trade balance), politics, and national resource strength, the U. S. should begin a large-scale synthetic fuel industry without regard to price maneuvers by foreign suppliers.

According to the selections of Section 10, the fuels for automotive transportation – in order of preference – for the near term are conventional gasoline and distillate fuels (dominant), supplemented by –

1. Gasoline from oil shale
2. Gasoline from coal
3. Distillate (diesel) oils from shale
4. Distillate (diesel) oils from coal
5. Methanol from coal.

The next two fuels in order of preference are SNG and hydrogen, both from coal. SNG is subject to priority demands by the gas utility industry and would be available for automotive use in limited quantities only. Hydrogen suffers from a moderate technology gap in practical tankage on-board a vehicle. Further, its production from coal and water would require competition with SNG, gasoline and distillates, and possibly methanol for the same resources. Production of hydrogen from nuclear process heat and water suffers from a severe technology gap.

11.1.1 Oil Shale Development Scenario According to Models I and II

Several areas in the U.S. contain oil shale deposits. Only the Green River Formation is considered adequate for commercialization of the oil shale industry prior to 2000. The Green River Formation consists of 25,000 square miles (16 million acres) in portions of Wyoming, Colorado, and Utah. It contains the equivalent of 1800 billion barrels of shale oil in oil shale seams that are more than 10 feet thick and that contain more than 15 gal/ton. In fact, an estimated 600 billion barrels can be obtained from shale containing more than 30 gal/ton from this formation.

The commercialization of the oil shale industry cannot begin until the Federal Government leases the land. Nearly 80% of the Green River Formation is on Federal land. Furthermore, approximately 60% of this acreage is under a clouded jurisdictional issue because of the existence of previously issued mining rights. Court rulings relative to these claims must be obtained before 1980; otherwise, significant delays in commercialization will occur. The current leasing schedule of the Federal Government, one lease per month for a 6-month period during the first half of 1974, has been completed. The first four of these leases attracted high bids, but the last two (probably requiring in situ processing) failed to attract interest. The purpose of these six leases was to give industry an opportunity to build demonstration units on land containing the high-quality oil shale. To our knowledge, future leasing schedules do not exist at this time.

The present law permits leases totaling not more than 5120 acres for each owner. This is not sufficient to encourage industry development because 1) it does not provide adequate higher quality shale for continued long-term operation with second-generation plants by the same party, and 2) it does not allow a single operation sufficient reserves to sustain a

100,000-150,000 bbl/day operation. Minimum holdings of up to 25,000 acres are needed to provide adequate minable shale per plant for a long-term commercial operation. Another major leasing policy issue that needs to be addressed is water rights. The industry cannot be developed efficiently if water rights are not as available as mineral rights in the proper proportions. The other constraints relative to the commercialization of this industry are the availability of proved technology, capital, and skilled labor.

The two major options in oil shale technology are mining-plus-surface processing and in situ processing. The mining-plus-surface processing is considered to be in the early stages of known technology, despite the fact that no demonstration plants are in operation or under construction. A pattern process for the production of gasoline and distillates from oil shale and its economics are described in Appendix B. Government and industry have expended much effort on evaluating this technology over the last 30 years at the experimental and pilot-plant levels. On the other hand, in situ processing must still be placed in the experimental category.

The schedule of oil shale development according to Model I implications for the near-term time frame is presented in Table 11-1. The bases are 1 barrel of crude shale oil at 5.8 X 10^6 Btu (high heating value) and a refining-to-product efficiency of 90%. The schedule of oil shale development according to Model II implications for the near-term time frame also is presented in Table 11-1.

Table 11-1. OIL SHALE TO GASOLINE AND DISTILLATES ACCORDING TO MODELS I AND II FOR THE NEAR TERM

Year	No. of New Plants and Vol, bbl/day	Total No. of Plants and Vol, bbl/day	Total Vol, bbl/day	Annual Production: Shale Oil (10^{15} Btu)	Annual Production: Gasoline and Distillates (10^{15} Btu)
Model I					
1975	Pilot Plants Only		--	--	--
1980	3 at 100,000	3 at 100,000	300,000	0.63	0.57
1985	7 at 100,000	10 at 100,000	1,000,000	2.09	1.88
Model II					
1975	Pilot Plants Only		--	--	--
1980	4 at 50,000	4 at 50,000	200,000	0.42	0.38
1985	4 at 100,000	4 at 100,000	600,000	1.25	1.12

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11.1.2 Coal-to-Liquid Fuels Scenario According to Models I and II

Coal can be processed with water to produce the candidate alternative fuels: SNG (methane), gasoline, and distillate hydrocarbons, and methanol. Pattern processes and their economics are described in Appendix B.

The major coal reserves available for use in these conversions could be mined in several areas. In the West, Montana, Wyoming, and North Dakota and the Four Corners area (New Mexico) have sufficient reserves of both coal and water for the development of large-scale industries. In these areas, water does become an eventual limiting factor on industry size. In the East, water is generally not a limiting factor, and the states of Illinois, Kentucky, West Virginia, Pennsylvania, and Ohio (and others) have coal reserves that could be further developed for synthetic fuel production. Here, other factors, such as real estate availability, terrain, and strip-mining laws, would be limiting. The number of coal-to-liquid and -gaseous fuel plants that could be built, of course, is limited by capital investment and product selling prices. In general, the higher the (real) price of the product, the higher the productive level because marginal mining and distant water supplies then will be utilized.

From water availability studies, we conclude that process efficiency and water requirements will become important to coal-based fuels at the beginning of the far-term time frame. Hence, in the near term, large-scale development of a process or synthesis route that is inordinately water-consuming would be unwise. In a coal-to-fuel process, water is used for two major purposes: for cooling or heat rejection to the environment, and for supplying hydrogen to the synthesized molecule as required by chemistry. The most efficient process requires the least cooling water, and the molecule with the smallest hydrogen-to-carbon ratio requires the least synthesis water. From our process studies, we deduce the following overall thermal efficiencies:

- Coal to SNG, 65-70%
- Coal to gasoline and distillates, 61-67%
- Coal to methanol, 41-46%

From chemistry, the mole ratio of hydrogen to carbon is as follows:

Table 11-2. COAL TO SNG AND EITHER GASOLINE PLUS DISTILLATES OR METHANOL ACCORDING TO MODELS I AND II FOR THE NEAR TERM

	1975	1980	1985
Model I			
SNG			
No. of Plants and Vol, 10^6 CF/day	Pilot Plants Only	12 at 250	24 at 250
Daily Production, 10^9 Btu	--	2850	5700
Annual Production, 10^{15} Btu	--	1.0	2.0
Gasoline and Distillates			
No. of Plants and Vol, 1000 bbl/day	Pilot Plants Only	1 at 100	2 at 100, 2 at 150
Annual Production, 10^6 bbl	--	36	180
Annual Production, 10^{15} Btu	--	0.22	1.08
Methanol			
No. of Plants and Vol, 1000 bbl/day	Pilot Plants Only	1 at 200	2 at 200, 2 at 300
Annual Production, 10^6 bbl	--	72	360
Annual Production, 10^{15} Btu	--	0.22	1.08
Model II			
SNG			
No. of Plants and Vol, 1000 CF/day	Pilot Plants Only	6 at 250	12 at 250
Daily Production, 10^9 Btu	--	1425	2850
Annual Production, 10^{15} Btu	--	0.5	1.0
Gasoline and Distillates			
No. of Plants and Vol, 1000 bbl/day	Pilot Plants Only	1 at 100	4 at 100
Annual Production, 10^6 bbl	--	36	144
Annual Production, 10^{15} Btu	--	0.22	0.86
Methanol			
No. of Plants and Vol, 1000 bbl/day	Pilot Plants Only	1 at 200	4 at 200
Annual Production, 10^6 bbl	--	72	288
Annual Production, 10^{15} Btu	--	0.22	0.86

- SNG (CH$_4$), 4:1
- Gasoline (isooctane), 2.25:1
- Methanol (CH$_3$OH), 4:1

Hence, methanol from coal is the most water-intensive of the three synthesis processes.

Because of the priority demands of the natural gas utility industry, plans already made, mineral and water rights, and capital already committed, SNG will be made from coal. As a result, three near-term options remain for alternative automotive fuels: gasoline and distillates, methanol, or a combination. For illustration in this and the other time frames, we have tabulated potential industry growth for both gasoline and methanol from coal. However, because of a lack of resources, mainly water, only one or the other would be practical on a large scale. We recommend gasoline and distillates as the most advantageous.

Table 11-2 shows the coal-to-fuel industry projection according to Models I and II implications. SNG is included because it is assumed to occur, and the unused coal and water resources remain available for gasoline and distillates or methanol.

11.1.3 Summary for Near-Term Time Frame

The synthetic fuel production rates of Tables 11-1 and 11-2 are included (inherently) in the energy supplies of Models I and II. As a result, we face energy deficits in 1975 and 1980, but in 1985 a state of self-sufficiency can be achieved for Model I only, as shown in Table 11-3. In 1985 according to

Table 11-3. TRANSPORTATION ENERGY SUPPLY AND DEMAND ACCORDING TO MODEL I FOR THE NEAR TERM

	1975	1980	1985	% of 1985 Market
		10^{15} Btu		
Fuel Demand (Nonelectric)	19.4	22.8	26.4	
Domestic Crude Fuels	13.0	15.0	17.4	63
Conventional Deficit	6.4	7.8	9.0	
Shale Oil Fuels (Table 11-1, 55%)	Nil	0.3	1.0	4
Coal Fuels (Table 11-2, 55%)*	Nil	0.1	0.6	2
Reallocated Coal to Fuel	Nil	Nil	5.9	21
Reallocated Nuclear to Fuel	Nil	Nil	2.8	10
Required Fuel Imports	6.4	7.4	(1.3)	

* Gasoline and distillates or methanol.

Model I, 8.7 X 10^{15} Btu is potentially available as electricity or as a synthetic fuel; see Table 4-7. This energy is not included in Tables 11-1 or 11-2, but it would be available to the transportation market sector. By reallocation of the energy supply, as permitted by the models (which are not formulas for allocation), the excess coal and nuclear energy of the electricity conversion sector of Model I is used to supply this 8.7 X 10^{15} Btu of "fuel." One such allocation is as follows:

16.8 X 10^{15} Btu (from coal) X 0.35 = 5.9 X 10^{15} Btu (fuel)

8.0 X 10^{15} Btu (from nuclear heat) X 0.35 = 2.8 X 10^{15} Btu (fuel)

Synthesis of this fuel will have to be in addition to that scheduled in Tables 11-1 and 11-2. If we do not develop nuclear process heat as an energy source for a synthetic fuel by 1985, e.g., hydrogen from water, which must be tanked adequately, or electricity for use in an electric car, we will not utilize the potentially available 2.8 X 10^{15} Btu, and we will have a deficit in 1985.

The disastrous situation of not conserving energy coupled with a slower rate of development of natural resources is shown in Table 11-4 for Model II.

Table 11-4. TRANSPORTATION ENERGY DEMAND AND SUPPLY ACCORDING TO MODEL II FOR THE NEAR TERM

	1975	1980	1985	% of 1985 Market
		10^{15} Btu		
Fuel Demand (Nonelectric)	19.1	22.4	25.4	
Conventional Supply	11.8	13.2	13.2	52
Conventional Deficit	7.3	9.2	12.2	
Shale Oil Fuels (Table 11-1, 55%)	Nil	0.2	0.6	2
Coal Fuels (Table 11-2, 55%)*	Nil	0.1	0.5	2
Reallocated Coal-Based Fuel	Nil	Nil	Nil	
Reallocated Nuclear-Based Fuel	Nil	Nil	Nil	
Required Fuel Imports	7.3	8.9	11.1	44

* Gasoline and distillates or methanol.

11.2 Mid-Term Time Frame (1985-2000)

During the mid-term time frame, the commercial development of synthetic or substitute fuels will be expanded greatly. According to Model I projections, by the year 2000, the SNG industry reaches 80% of its ultimate capacity, coal to distillate fuels reaches about 75% of capacity, or alternatively, coal to methanol reaches 80% of its capacity. The oil shale industry reaches 100% of expected capacity by the year 2000. According to Model II projections, the industry growth rates are slower and the ultimate capacities are lower; thus similar growth proportions are observed during this time frame. The principal limit on the ultimate capacities for these new industries is water availability in the Western States. As in the near-term time frame, other governing factors also will change as time progresses; these limitations on growth rate are a result of fuel economics and capital for investment, skilled labor supply, environmental constraints, etc.

Always growing at a rapid pace but becoming a major contributor to energy supply in this time frame is nuclear energy. According to Model I, the mid-term time frame is a period of self-sufficiency if, among other things, we develop this nuclear energy by synthesizing a fuel. As in the near-term time frame, coal and nuclear energy are potentially available to the transportation sector of the economy. In this time frame, the nuclear heat portion becomes almost as large as the reallocated coal fuel. This projection assumes the success of breeder reactors as a supply of fissile fuels 50-75 times greater than the U^{235} that is naturally obtainable. However, this time frame also could be a deceiving one. We will need to learn how to convert nuclear energy into a fuel with high efficiency. Model I assumes a 35% overall conversion efficiency for all time frames, but this level of technology becomes inadequate for self-sufficiency by the year 2000. Model II always requires imported fuels, primarily because of poor energy conservation (high demand) and large energy losses during conversion processes.

According to the selections of Section 10, the fuels for automotive transportation — in order of preference — for the mid term are conventional gasoline and distillate fuels (no longer dominant by Model I), supplemented by —

1. Gasoline from oil shale and coal
2. Distillate (diesel) oils from oil shale and coal
3. Methanol from coal.

The next two fuels in order of preference are SNG from coal and hydrogen either from coal or nuclear heat (if the technology gap is solved). As in the near term, SNG is subject to priority demands and would be available for automotive use in limited quantities only. By 1985, we can assume solution of the hydrogen tankage problem (a moderate technology gap), but the nuclear synthesis technology may not be developed until nearer 2000.

11.2.1 Oil Shale Development Scenario According to Models I and II

In the late 1980's and the early 1990's, water supply constraints will be more severe than other constraints. The Bureau of Reclamation's estimate of water availability in the Green River area is 5.8 million acre-ft/yr (122×10^6 bbl/day). However, the Bureau also estimates that only 83% (101×10^6 bbl/day) can be utilized. At present, about 55% of the water that can be effectively utilized is being used, and about 35% is committed to future use. Most of the remainder, 11%, is uncommitted and could be made available for the commercialization of this industry. This 11% would support the process requirements but not land reclamation requirements for the production of about 1.7×10^6 bbl/day of shale oil, approximately 50% of the anticipated total production according to Model I. The most expedient method of obtaining the additional 11×10^6 bbl/day water required is to redirect 25-30% of the potential water reserves committed for future use elsewhere into the commercialization of the oil shale industry.

For shale oil production from the Green River Formation, water requirements could be supplied by the Colorado, White, and Roaring Fork Rivers in Colorado, several reservoirs, and the West Divide Water Project. In Utah, the White River would be the main supply, and in Wyoming, the Green River and Flaming Gorge Reservoir would be sources of supply. For Model I, the ultimate production rate of shale oil is 3.55×10^6 bbl/day, or 6.7×10^{15} Btu/yr, as gasoline and distillate fuels. The total Model I supply is about 700,000 acre-ft/yr. For Model II, no future additions to the water supply are assumed. The ultimate supply is 341,000 acre-ft/yr, and the ultimate production rate is 1.7×10^6 bbl/day (syncrude), or 3.2×10^{15} Btu/yr (fuel).

The mid-term schedule for oil shale development according to both Model I and Model II is presented in Table 11-5.

Table 11-5. OIL SHALE TO GASOLINE AND DISTILLATES ACCORDING TO MODELS I AND II FOR THE MID TERM

				Annual Production	
Year	No. of New Plants and Vol, bbl/day	Total No. of Plants and Vol, bbl/day	Total Vol, bbl/day	Shale Oil	Gasoline and Distillates
				10^{15} Btu	
Model I					
1990	10 at 150,000	10 at 100,000 10 at 150,000	2,500,000	5.22	4.7
1995	5 at 150,000	10 at 100,000 15 at 150,000	3,250,000	6.79	6.3
2000	3 at 100,000	13 at 100,000 15 at 150,000	3,550,000	7.41	6.7
Model II					
1990	2 at 100,000 2 at 150,000	4 at 50,000 6 at 100,000 2 at 150,000	1,100,000	2.29	2.1
1995	3 at 100,000 2 at 150,000	4 at 50,000 9 at 100,000 4 at 150,000	1,700,000	3.55	3.2
2000	None	4 at 50,000 9 at 100,000 4 at 150,000	1,700,000	3.55	3.2

11.2.2 Coal-to-Liquid-Fuels Scenario According to Models I and II

As with oil shale, water is a constraint on the ultimate size of a coal-to-gaseous and -liquid fuel industry. Because the SNG industry appears imminent, it must be considered as a priority user of coal, and the remaining reserves – limited by water availability in the West – could be used for gasoline and distillates or methanol production.

By 2000, according to Model I, 93 SNG plants are to be on-line at a production rate of 250 million CF of SNG per day. Although this is a very optimistic projection, six such plants are already firmly planned or on order.

The coal-to-synthetic and -substitute fuel industry will reach maturity in the far-term time frame, and geographical areas and water limitations are discussed in that scenario. Table 11-6 presents the coal-to-SNG and gasoline plus distillate or methanol schedules for Models I and II. Again,

Table 11-6. COAL TO SNG AND EITHER GASOLINE PLUS DISTILLATES OR METHANOL ACCORDING TO MODELS I AND II FOR THE MID TERM

	1990	1995	2000
Model I			
SNG			
No. of Plants and Vol, 10^6 CF/day	48 at 250	72 at 250	93 at 250
Daily Production, 10^9 Btu	11,400	18,000	22,250
Annual Production, 10^{15} Btu	4.1	6.5	8.0
Gasoline and Distillates			
No. of Plants and Vol, 1000 bbl/day	2 at 100 10 at 150	2 at 100 20 at 150	2 at 100 30 at 150
Annual Production, 10^6 bbl	612	1152	1692
Annual Production, 10^{15} Btu	3.7	6.9	10.2
Methanol			
No. of Plants and Vol, 1000 bbl/day	2 at 200 10 at 300	2 at 200 15 at 300	2 at 200 20 at 300
Annual Production, 10^6 bbl	1224	1764	2304
Annual Production, 10^{15} Btu	3.7	5.3	6.9
Model II			
SNG			
No. of Plants and Vol, 10^6 CF/day	30 at 250	50 at 250	70 at 250
Daily Production, 10^9 Btu	7125	11,875	16,625
Annual Production, 10^{15} Btu	2.6	4.3	6.0
Gasoline and Distillates			
No. of Plants and Vol, 1000 bbl/day	6 at 100 5 at 150	6 at 100 12 at 150	6 at 100 20 at 150
Annual Production, 10^6 bbl	486	864	1296
Annual Production, 10^{15} Btu	2.9	5.2	7.8
Methanol			
No. of Plants and Vol, 10^6 bbl	6 at 200 5 at 300	6 at 200 10 at 300	6 at 200 14 at 300
Annual Production, 10^6 bbl	972	1512	1940
Annual Production, 10^5 Btu	2.9	4.5	5.8

gasoline and methanol cannot both be made from the same resources, and we recommend gasoline (and distillates) as the choice providing the largest ultimate fuel supply.

11.2.3 Summary for Mid-Term Time Frame

Table 11-7 presents the energy demand and supply situation at the end of the mid-term time frame for Models I and II. Potential market penetrations also are tabulated. The nuclear energy-to-fuel supply will only be available (Model I) if technology permits. If not, Model I imports for transportation will be 6.2 X 10^{15} Btu, instead of 0.3 X 10^{15} Btu.

Table 11-7. TRANSPORTATION ENERGY DEMAND AND SUPPLY ACCORDING TO MODELS I AND II FOR THE YEAR 2000

	Model I		Model II	
	10^{15} Btu	Market %	10^{15} Btu	Market %
Fuel Demand (Nonelectric)	40.0		41.3	
Domestic Crude Fuels	16.9	42	13.3	32
Conventional Deficit	23.1		28.0	
Shale Oil Fuels (Table 11-5, 55%)	3.7	9	1.7	4
Coal Fuels (Table 11-6, 55%)*	5.6	14	4.3	10
Reallocated Coal to Fuel†	7.6	19	Nil	--
Reallocated Nuclear to Fuel‡	5.9	15	Nil	--
Required Fuel Imports	0.3	1	22.0	54

* Gasoline and distillate oil.

† Hydrocarbons, methanol, or hydrogen.

‡ Possibly hydrogen.

11.3 Far-Term Time Frame (2000-2020)

For the distant time period beyond 2000, quantitative projections with any degree of certainty are impossible. Continuing to follow the two models of energy demand and supply, we show the procedures for estimating energy supplies, fuel needs, and the penetration of the transportation market sector by alternative fuels.

In this distant time period, the nuclear energy supply becomes dominant. Coal is still a major contributor to substitute fuel synthesis, and its annual production potential as gasoline and distillates is about 200% of that of oil shale. If methanol from coal were the synthesis route, its ultimate production rate would be about 125% of that of oil shale. Water limitations restrict oil shale industry growth in the mid term and coal processes in the far term.

According to the selections of Section 10, the fuels for automotive transportation – in order of preference – for the far term are conventional gasoline and distillate fuels (a minor contributor in Model I and large imports in Model II), supplemented by –

1. Gasoline from coal and oil shale
2. Distillate (diesel) fuels from coal and oil shale
3. Nuclear-based hydrogen.

The next two fuels in order of preference are methanol and SNG from coal. Again, the supplies of SNG available to the transportation sector are limited to about 1-2 X 10^{15} Btu/yr, a minimal contribution by 2000. We assume the solution of the hydrogen tankage problem during the mid term; the nuclear synthesis technology should be a reality in the far term.

11.3.1 Nuclear-Based Fuels (Hydrogen) Scenario

For the synthesis of hydrogen from water, nuclear heat is available from HTGR's using helium or hydrogen as the heat-transfer medium. In addition, breeder reactors are operating to supply part of the fuel needed by the HTGR's. Because of the anticipated temperature limitations, fast-breeder reactors probably are not adequate for producing hydrogen by thermochemical water-splitting. Breeders serve as heat sources for electricity generation, and this electricity can be used for the electrolysis of water to produce hydrogen. In addition, process heat and electricity might be available from fusion reactors whose commercialization should begin in the far-term time frame.

From the basic assumptions of Model I, we find that the U.S. experiences energy deficits during the period 2000-2020. Significant fuel importation would be necessary to satisfy transportation energy demands, primarily because of the overall efficiency of 35% assumed for the conversion of nuclear heat and coal and fuel. If this assumption is relaxed slightly for this far-term scenario, the situation improves greatly. If we assume overall conversion efficiencies of 42% for nuclear heat to electricity and thermochemical hydrogen and for coal to fuel (hydrocarbons or hydrogen), in 2020 according to Model I, 114.3 X 10^{15} Btu is available as fuel and electricity. Of this quantity, 74.1 X 10^{15} Btu (electricity) is required to fill all sector energy deficits except transportation, and the remaining 40.2 X 10^{15} Btu (fuel) is left to alleviate the transportation shortfall of 41.7 X 10^{15} Btu. A possible reallocation within Model I is 23.5 X 10^{15} Btu of nuclear-based hydrogen and 16.7 X 10^{15} Btu of coal-based fuel. This coal-based fuel is in addition to that shown in Table 11-8, and we do not know where the additional water supplies required can be secured. A solution is that this fuel be solvent-refined coal. If this reallocation is not the case, a domestic deficit can occur, requiring imports of about 20 X 10^{15} Btu of fuel in 2020 by Model I. In contrast, the domestic deficit (imports) in Model II (nuclear and coal conversions at 35%) would be 39.8 X 10^{15} Btu. The energy quantities considered above for Models I and II are contained in Table 11-9.

Table 11-9. TRANSPORTATION ENERGY DEMAND AND SUPPLY ACCORDING TO MODELS I AND II FOR THE YEAR 2020

	Model I		Model II	
	10^{15} Btu	Market %	10^{15} Btu	Market %
Fuel Demand (Nonelectric)	69.4		66.2	
Domestic Crude Fuels	16.9	24	13.0	20
Conventional Deficit	52.5		53.2	
Shale Oil Fuels (55% Production)	3.7	5	1.8	2
Coal Fuels (Table 11-8, 55%)*	7.1	10	5.6	8
Reallocated Coal to Fuel†	16.7	24	3.0	5
Reallocated Nuclear to Fuel‡	23.5	34	3.0	5
Required Fuel Imports	1.5	2	39.8	60

* Gasoline plus distillate oil.

† Unspecified hydrocarbon or solvent-refined coal.

‡ Hydrogen.

Table 11-8. COAL TO SNG AND EITHER GASOLINE DISTILLATES OR METHANOL ACCORDING TO MODELS I AND II FOR THE FAR TERM

	2010	2020
Model I		
SNG		
No. of Plants and Vol, 10^6 CF/day	105 at 250	117 at 250
Daily Production, 10^9 Btu	15,000	27,800
Annual Production, 10^{15} Btu	9.0	10.0
Gasoline and Distillates		
No. of Plants and Vol, 1000 bbl/day	2 at 1000 35 at 150	40 at 150
Annual Production, 10^6 bbl	1962	2160
Annual Production, 10^{15} Btu	11.8	13.0
Methanol		
No. of Plants and Vol, 1000 bbl/day	2 at 200 22 at 300	2 at 200 22 at 300
Annual Production, 10^6 bbl	2520	2520
Annual Production, 10^{15} Btu	7.6	7.6
Model II		
SNG		
No. of Plants and Vol, 10^6 CF/day	30 at 250	90 at 250
Daily Production, 10^9 Btu	19,050	21,400
Annual Production, 10^{15} Btu	6.9	7.7
Gasoline and Distillates		
No. of Plants and Vol, 10^6 CF/day	6 at 100 25 at 150	10 at 100 25 at 150
Annual Production, 10^6 bbl	1566	1710
Annual Production, 10^{15} Btu	9.4	10.2
Methanol		
No. of Plants and Vol, 1000 bbl/day	6 at 200 14 at 300	6 at 200 14 at 300
Annual Production, 10^6 bbl	1940	1940
Annual Production, 10^5 Btu	5.8	5.8

11.3.2 Oil-Shale-Development Scenario, Models I and II

According to Models I and II, there is no further growth in the oil shale-to-hydrocarbon fuels industry beyond the levels of 2000 (Table 11-5). As old plants become obsolete or as oil shale deposits are depleted, new plants and mines are brought on-line to compensate, but net production rates are essentially unaffected. These rates are limited by the process water supply. In 2010 and 2020 for Model I, the production rate is 3550 bbl/day of syncrude, or 6.7 X 10^{15} Btu/yr of fuel. In 2010 and 2020 for Model II, the production rate is 3000 bbl/day of syncrude, or 5.6 X 10^{15} Btu/yr of fuel.

11.3.3 Coal-to-Liquid-Fuels Scenario, Models I and II

The production rates of SNG and gasoline plus distillate oils or methanol for the far-term time frame are shown in Table 11-8.

For Model I, we assume the operation of 105 SNG plants by 2010 and 117 plants by 2020 as the ultimate production level (10 X 10^{15} Btu). In addition, we can have 40 coal-to-liquid hydrocarbon fuels plants by 2020, or 24 coal-to-methanol plants. Optimistic coal and water supplies can be approximately apportioned to support this level of industry.

For Model II, we assume 80 SNG plants in 2010 and 90 plants in 2020 as the ultimate production level (7.7 X 10^{15} Btu). In addition, we can have 35 coal-to-liquid hydrocarbon fuel plants by 2020, or 20 coal-to-methanol plants. Known (uncommitted) coal and water supplies can be approximately apportioned to support this level of industry.

For Model I, we must place 82 SNG plants in the East, 30 in Illinois alone. In the West, optimistically, we could utilize 1 million acre-ft/yr of water in Montana and Wyoming, 375,000 acre-ft/yr of water in North Dakota, and 150,000 acre-ft/yr of water in the Four Corners area (New Mexico). A 250 million CF/day SNG plant requires about 15,000 acre-ft/yr of water. Therefore, we can place 25 SNG plants in North Dakota and 10 in the Four Corners area. This leaves the Montana and Wyoming reserves available for gasoline and distillate hydrocarbon production or methanol synthesis. Roughly, a barrel of coal-produced gasoline plus distillate requires 3.5 barrels of water, and a barrel of coal-produced methanol requires about 3 barrels of water. The result is 40 gasoline and distillate fuel plants at 150,000 bbl/day, or about 24 methanol plants at 300,000 bbl/day (13 X 10^{15} Btu/yr hydrocarbon versus 7.6 X 10^{15} Btu/yr methanol output).

For Model II, we must place 55 plants in the East, 25 in Illinois. In the West, we could utilize 785,000 acre-ft/yr of water in Montana and Wyoming, 375,000 acre-ft/yr of water in North Dakota, and 150,000 acre-ft/yr of water in the Four Corners area. The East plus North Dakota and the Four Corners area support the 90 SNG plants required. We would then site about 4,750,000 bbl/day of gasoline and distillates, or about 5,400,000 bbl/day of methanol, in Montana and Wyoming.

11.3.4 Summary for Far-Term Time Frame

Table 11-9 presents the energy demand and supply situation at the end of the far-term time frame for Models I and II. Potential market penetrations also are tabulated. The Model I reallocation is based on nuclear and coal-to-fuel conversion efficiencies of 42%.

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16. ABSTRACT

The objective of this study is to assess the technical and economic feasibility of alternative fuels for automotive transportation, specifically: identification and characterization of potentially feasible and practical alternative fuels that can be derived from domestic, nonpetroleum energy resources; technical and economic assessments of the most promising alternative fuels for three specific time frames; identification of pertinent fuels and research data gaps and recommendations of alternative fuel(s) to best satisfy future U.S. automotive transportation requirements. Major emphasis in the selection of alternative fuels is placed on long-term availability from domestic resources. Economics, competition with other energy a;;lications for limited energy resources, safety, handling, system efficiency, environmental impacts, and engine and fuel distribution system compatibility are also taken into account. This study provides background information for the develpment of U.S. energy programs pertaining to chemical fuels.

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